Ontario Hydro

Submission on 1987 Electricity Rates

April 1986

Ontario Hydro

Submission

on

1987

Electricity Rates

Ontario Hydro's submission to the Ontario Energy Board in support of the proposal to the Minister of Energy concerning 1987 electricity rates for municipal utilities and direct customers.

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Chapter 1
GENERAL

1. Ontario Hydro files this submission in support of its proposal to increase electricity rates, effective January 1, 1987, by an average of 4.6% for municipal utilities and by an average 5.0% for direct customers. The corresponding average "all customers" rate increase, which also includes Hydro's rural customers, is 4.9%. Pursuant to section 37 of the Ontario Energy Board Act, the proposal to change rates effective January 1, 1987, was made to the Minister of Energy in a letter dated April 15, 1986 (see Appendix 1).

2. The proposal for 1987 rates reflects Hydro's corporate strategy for the 1980s, which has a reduced emphasis on the construction of generating facilities, and a more active approach to the marketing of electricity.

3. Hydro's proposal for 1987 rates was developed taking into account near-term forecasts of a period of relatively stable electricity price increases, close to expected rates of inflation, which will both recover increased costs and improve financial soundness.

4. Key results and planning assumptions are shown in table 1-1. The 1987 rate year is characterized by

- a proposed average electricity rate increase which is close to the expected rate of inflation;
- an economic outlook which assumes continuing low inflation, stable interest rates, and a slight improvement in the value of the Canadian dollar;
- primary sales growth of 2.6%, reflecting moderate economic growth and increased usage of electricity by customers;
- financial soundness slightly improved from the expected 1986 level, although remaining below target levels and the levels expected in Financial Forecast 1985-1988 (March 1985);

Key results and planning assumptions — Table 1-1

	1985	1986	1987
Rate increase %			
All customers average	8.6	4.0	**4.9**
Municipal customers	8.5	4.0	**4.6**
Direct customers	8.8	4.3	**5.0**
Rural retail	8.7	3.8	**5.8**
Economic outlook			
CPI-Toronto (% change)	3.9	4.2	**4.5**
Long-term interest rate (%)	11.2	10.2	**10.1**
Canadian $ (in US$)	73.7	71.8	**72.9**
Electricity sales (TW.h)			
Primary sales	116.0	118.0	**121.1**
Secondary sales	8.6	8.7	**9.3**
Financial indicators			
Debt ratio	0.830	0.831	**0.830**
Interest coverage			
- level	1.14	1.11	**1.11**
- quality	0.55	0.63	**0.69**
Cash flow coverage	1.02	1.06	**1.17**
Net income - % of target	60	55	**60**
Financing ($M)			
Capital program costs	2605	2683	**2252**
Borrowing	1794	1858	**2100**
Current operations ($M)			
Costs	4265	4577	**4939**
Net income	360	301	**294**
Secondary revenue	(351)	(349)	**(360)**
Revenue requirement	4274	4529	**4873**

- declining capital program costs due to the completion of the remaining units of Pickering B and Bruce B;

- borrowing of about $2 billion; and

- increased fixed charges and OM&A costs, reflecting the coming into service of nuclear units in 1986 and 1987, moderated by relatively constant fuel costs resulting from the increased nuclear generation.

The 1987 Revenue Requirement

5. This submission supports Hydro's 1987 revenue requirement, that is, the revenues to be received from Hydro's primary customers (essentially all Ontario customers).

6. Revenue requirement equals total operating costs, plus net income requirement, less secondary revenues (essentially revenues from export sales). The components of revenue requirement are the following

- fuel and fuel-related (chapter 4);

- operation, maintenance and administration (chapter 5);

- interest and foreign exchange (chapter 7);

- depreciation (chapter 8);

- net income (chapter 9); less

- secondary revenues (chapter 4).

7. A 1987 rate increase of 4.9% is expected to provide a slight improvement in financial soundness from that anticipated for 1986, with the current expectation of achieving close to target levels in 1988, and target levels in 1989.

8. Table 1-2 and chart 1-3 display the components of revenue requirement for the period 1985-1987. Dollar amounts in table 1-2 (and generally in this document) are rounded to the nearest million; consequently, totals may differ from the sum of the components.

9. The forecast revenue requirement for 1987 is $4873 million, $344 million greater than for 1986, as shown in table 1-2. $117 million of the increase is expected to be obtained from increased primary sales, leaving the remaining $227 million to be recovered through the proposed 4.9% rate increase.

Revenue requirement **Table 1-2**

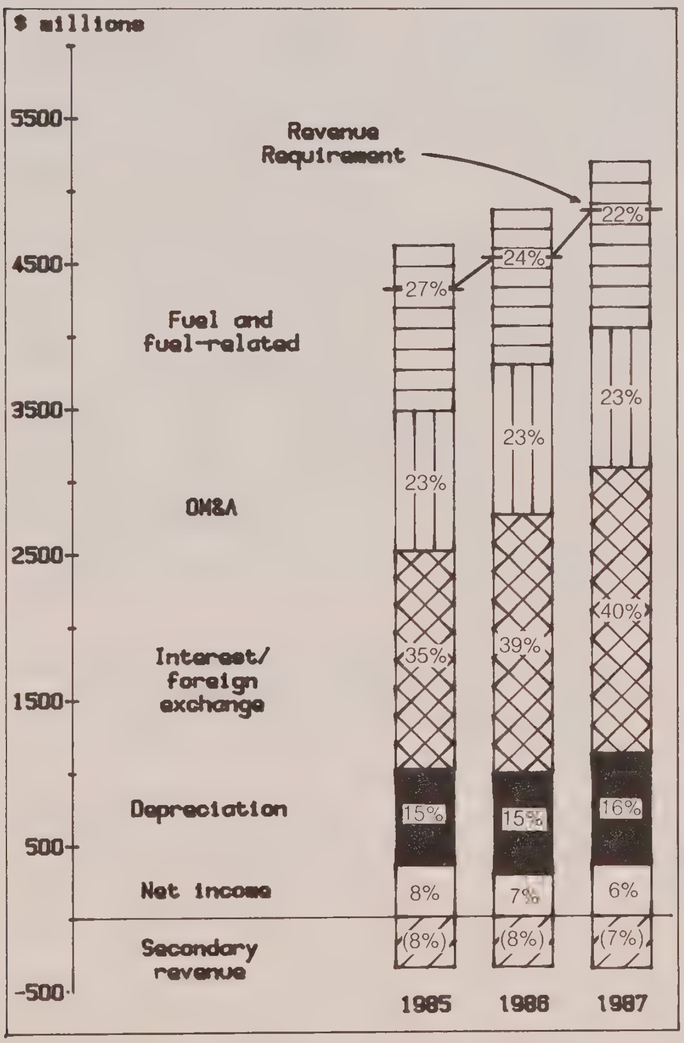
$ millions

	1985	1986	**1987**
Fuel and fuel-related	1143	1069	**1090**
Operation, maintenance and administration	966	1036	**1120**
Interest and foreign exchange	1501	1775	**1966**
Depreciation	655	696	**762**
Net income	360	301	**294**
Revenues for secondary power and energy	(351)	(349)	**(360)**
Revenue requirement*	4274	4529	**4873**

* Primary revenues for 1985 and 1986

10. The forecast increase of $344 million in revenue requirement is due primarily to interest, depreciation and OM&A expense associated with additional generating units, and escalation in fuel and OM&A costs. With the new nuclear units in service and the return to operation of Pickering Units 1 and 2 in early 1987, the nuclear component of total energy resources increases from about 39% in 1985 to 53% in 1987. As a result, fuel and fuel-related costs remain below 1985 levels despite increasing electricity sales and moderately increasing coal and nuclear fuel prices.

Revenue requirement **Chart 1-3**



11. The reasons for the $344 million increase in revenue requirement and the 4.9% rate increase are summarized in table 1.4.

Factors causing increase in revenue requirement and rates **Table 1-4**

	Effect on 1987 revenue requirement ($ millions)	Effect on 1987 rates (% points)
Economic environment		
Cost escalation	78	1.7
Slightly improved Canadian dollar	(24)	(0.5)
Electricity sales		
Increased primary sales	62	(1.2)
System operation		
New facilities in-service	399	8.6
Reduced debt on in-service assets	(123)	(2.6)
Foreign debt maturities	(46)	(1.0)
Generation mix	20	0.4
Other	(22)	(0.5)
	344	4.9

Capital Program Costs

12. Capital program costs decline from $2.7 billion in 1986 to $2.3 billion in 1987. These costs consist primarily of expenditures on nuclear generation, and transmission and distribution projects. In 1987 it is expected that Pickering Units 1 and 2 will return to operation and that Bruce Unit 8 will be placed in service. In-service date assumptions used to develop the rate proposal (financial in-service dates) differ slightly from the Corporation's currently approved forecast in-service dates, as discussed in chapter 6 and in exhibit 6.1.2, "Capital Construction Program In-Service Date Assumptions."

Financing

13. Borrowing in 1987 is expected to consist of both intermediate and long term debt. Borrowing is forecast to increase from $1.9 billion in 1986 to $2.1 billion in 1987, due primarily to a higher level of debt maturities, partially offset by lower capital program costs.

Rate Structure

14. Hydro is deferring any further rate structure reform for the next two years. Meetings are being held between Hydro and the two major customer representative associations, the MEA (previously OMEA and AMEU) and AMPCO, to develop as much consensus as possible on rate structure reform for 1989 rates.

Accounting Policy

15. Accounting reviews undertaken and changes affecting the proposed 1987 rates are summarized in chapter 9 of this document. Included are

- accounting for Translation of Foreign Currency; and
- accounting for Uranium Fuel Supply in a Downsizing Environment.

16. In April 1986, the CICA released new recommendations on Accounting for Pension obligations. However, because of the time required to assess these recommendations, their impact has not been factored into the current forecast.

Changes in Outlook for 1987

17. Table 1-5 summarizes the changes in the 1987 revenue requirement since the forecast developed in April, 1985.

1987 revenue requirement - changes since April 1985 **Table 1-5**

$ millions

	Forecast for 1987 dated in April 1985*	1986	Change
Fuel and fuel-related	1148	1090	(58)
Operation, maintenance and administration	1076	1120	44
Interest and foreign exchange	1968	1966	(2)
Depreciation	773	762	(11)
Net income	408	294	(116)
Revenues for secondary power and energy	(458)	(360)	98
Revenue requirement	4916	4873	(43)
	====	====	===

* Based on forecast scenario ("soundness by 1988")

18. Major factors contributing to the changes shown in table 1-5 include

- a 4 percentage point reduction in expected inflation over 1985-1987, and a 3 cent deterioration in the 1987 forecast of the Canadian dollar;
- reductions in fuel costs from lower fuel prices and a higher forecast of hydraulic generation;

- increases in OM&A costs due mainly to an under-estimate of costs last year and a reduction in the Corporate program adjustment;

- a reduction in depreciation reflecting the deferral of the implementation of the service life extensions for fossil generating stations pending the results of the Demand/Supply Options Study; and

- a reduction in secondary revenues reflecting both lower volumes and lower U.S. dollar prices.

19. The impact of these factors and other changes, expressed as percentage points of rate increase, is shown in table 1-6.

20. The rate proposal has been developed from a set of "most likely" assumptions. For 1987, there is judged to be a greater risk associated with potential cost increases resulting from unfavourable changes in planning assumptions.

1986 Outlook Versus 1986 Budget

21. Net income for 1986 is forecast to be $301 million, $29 million lower than the $330 million in the 1986 Corporate Budget. This reduction reflects a lowering of the forecast US/Cdn exchange rate by about 2 cents, and a revision to the Corporate Adjustment included in OM&A costs to reflect 1985 actual experience, partly offset by the impact of in-service date delays.

1987 rate increase - changes since April 1985 Table 1-6

	1987 rate increase (% points)
April 1985 submission (forecast scenario)*	5.5
Corporate policy	
1986 rate decision (4.0% vs 3.6%)	(0.4)
1987 rate proposal (lower net income)	(2.4)
Economic environment	
Lower escalation (OM&A and fuel)	(1.5)
Lower secondary sales prices	1.4
Foreign exchange rate deterioration	0.8
Electricity sales	
Primary sales volume	0.9
Lower secondary sales volume	0.4
System operations	
Generation mix	(0.3)
In-service additions	(0.8)
OM&A Corporate adjustment	0.4
OM&A program cost changes	0.8
Deferral of fossil service life extensions	0.4
Other	(0.3)
April 1986 submission	4.9

* Financial Forecast 1985-1988

Chapter 2
ECONOMICS AND LOAD FORECASTING

ECONOMIC OUTLOOK

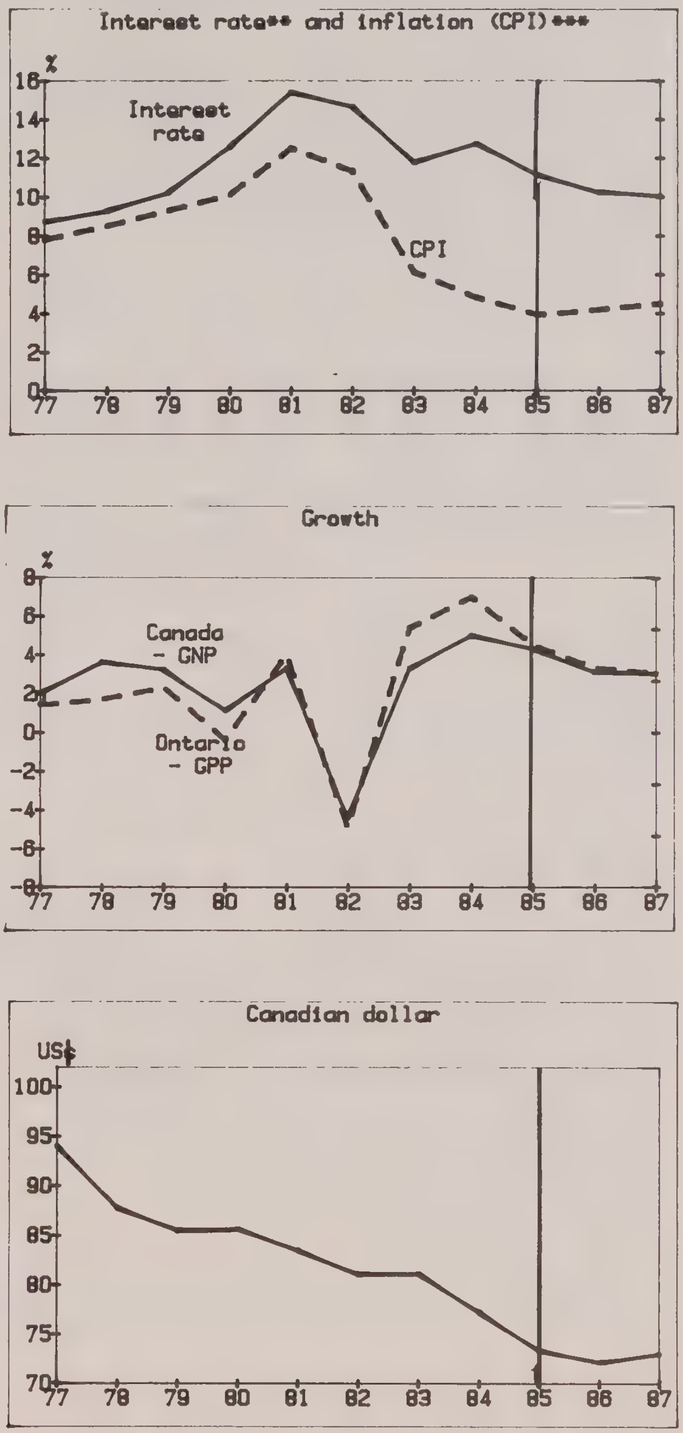
1. The economic assumptions embodied in this submission are based on the Economic Outlook, Winter Review, February 1986 (exhibit 2.1.4). A further overall economic review will be published in May 1986. Specific forecasts of interest and foreign exchange rates in this submission are based on the March 1986 Financial Markets Outlook (exhibit 2.1.6).

2. The Economic Outlook is prepared with the assistance of the Data Resources Incorporated (DRI) computer model of the Canadian economy. This model simulates the behaviour of the economy on the basis of responses to factors such as government spending and foreign trade. The DRI model is supplemented by models developed by Ontario Hydro for specific applications, including a macroeconomic model of the Ontario economy. However, Hydro's forecast model results incorporate the forecaster's judgment on factors such as government fiscal and monetary policy. Judgment included in Hydro's forecasts is subject to critical review, both internally and externally.

3. In 1986 we are entering the fourth year of economic growth following the 1981-82 recession. The outlook for continued moderate growth remains favourable, because there are no significant inflationary pressures foreseen through 1987. The recent decline in oil prices and the value of the US dollar relative to overseas currencies are both favourable factors for continued growth.

4. Chart 2-1 shows key forecast data in relation to historical values.

Historical and forecast data* **Chart 2-1**



* Values for each year are annual averages
** Government of Canada long-term bond rate
*** Consumer Price Index - Toronto

Comparison With The Submission On 1986 Rates

5. Table 2-2 provides a summary of several key indicators, and shows how the current forecast compares with the 1986 forecast presented by Hydro at last year's hearing. The 1986 rate proposal information in table 2-2 was contained in the May 1985 Economic Outlook (exhibit 2.1.5 from last year's hearing).

Comparison of forecasts for 1986 **Table 2-2**

Annual average % change

	1986 rate proposal	Current forecast
Real GPP growth - Ontario	1.5	3.3
CPI - Canada	4.9	4.0
CPI - US	4.8	3.6
Government bond rate (%)	11.5	10.2
Canadian dollar ($US)	.760	.718

Economic Growth

6. Economic growth in the United States in 1985 was fairly low, at 2.3%, because of weak consumer spending growth and a poor international trade position. Ontario usually depends heavily on the United States, because of the close links of the automobile sector (our most important industry) with the US market. In spite of this, Ontario managed to grow almost twice as fast as the United States, because of strong construction activity and stronger consumer spending.

7. The momentum of construction activity and consumer spending is expected to carry through into 1986, keeping growth ahead of that of the United States. Canada had a much deeper recession than the United States in 1982, and it has taken longer for confidence to recover. Canada lags behind events in the United States. Consumer spending in Canada continues to be strong while consumer spending in the United States is slowing.

8. In 1987, the US economy is expected to grow slightly higher than in 1986. This will help Ontario via increased exports. In 1987, the United States should be enjoying improved growth because of the delayed effect of the decline in the value of the US dollar which has taken place, improving the North American trade balance with the rest of the world. Lower oil prices benefit consumer spending, and should help the North American auto industry face competition from more fuel efficient foreign cars.

Growth - real GNP/GPP **Table 2-3**

Annual average % change

	1985	1986	1987
Ontario	4.5	3.3	**3.0**
Canada	4.5	3.1	**3.0**
United States	2.3	2.5	**3.0**

Inflation

9. The outlook for inflation is clouded by uncertainty over exactly where oil prices will settle, and the extent to which governments will allow the lower world price to be passed on to Ontario consumers. However, it is likely that lower oil prices will go a long way toward offsetting the higher inflation which would have resulted otherwise from the lower value of the Canadian dollar. The latter adds to inflation both by raising the prices of imported goods and by reducing the pressure of foreign competition on the pricing policies of Canadian producers. The rate of inflation in 1986 and 1987 is forecast to average just over 4% if oil prices recover somewhat.

Inflation **Table 2-4**

Annual average % change

	1985	1986	**1987**
CPI-Toronto	3.9	4.2	**4.5**
CPI-Canada	4.0	4.0	**4.5**
CPI-United States	3.8	3.6	**4.2**

Interest Rates

10. The Canadian prime rate is forecast to decline to 10 per cent by the end of 1986, once speculation against the Canadian dollar eases. Generally, observed interest rates should continue to be on a declining trend (relative to 1985) because of lower inflation and lower government deficits. The fact that inflation is lower than in the early 1980s makes real interest rates higher.

Interest rates - Ontario Hydro **Table 2-5**

Annual average % for debt issued - by term to maturity

	1985	1986	**1987**
Canada			
Short less than one year	9.1	9.4	**8.5**
Intermediate - 5 to 10 years	10.9	10.0	**9.8**
Long - greater than 10 years	11.4	10.4	**10.2**
United States			
Intermediate - 5 to 10 years	10.7	9.5	**9.5**
Long - greater than 10 years	11.4	10.0	**10.0**

Foreign Exchange Rates

11. As expected last year, the US dollar (and with it the Canadian dollar) fell sharply against the overseas currencies. In mid-March of 1986, the US dollar is down about 30% from its previous year values against the major foreign currencies. This is a welcome realignment that brings the US dollar close to its fundamental value and should, over time, reduce the huge US trade deficit. Further depreciation of the US dollar is not expected.

Foreign exchange rates **Table 2-6**

Foreign currency units per Canadian dollar - annual average

	1985	1986	**1987**
US$	0.73	0.72	**0.73**
DM	2.14	1.61	**1.60**
SFr	1.78	1.34	**1.38**

12. The Canadian dollar was the only industrial currency which fell against the US dollar even though the latter was also falling. Most forecasters were not expecting this to happen. The most plausible explanation is that the Bank of Canada excessively reduced Canada-US interest rate differentials in the fall of 1985. The collapse of oil prices was a further negative factor, since Canada is a net energy exporter. The government has now decisively expressed its support for the dollar, and this should allow the Canadian dollar to be fairly stable in the 71-73 US cents range over the next two years. Market confidence in the Canadian dollar is very fragile and there is considerable downside risk.

Oil and Gas Prices

13. The current world oil situation at the time of writing is extremely volatile. The price fell more than 50% in the first two months of the year based partly on speculation about excessive rates of oil production. It is expected that there will be some agreement among oil producers which will bring the international oil price up toward the $US 20 per barrel level over the next year. Over the medium term, growing world demand for oil is expected to lead to a firming of prices.

14. Canadian natural gas prices were slated to be deregulated in November of 1986. However, the decline in energy prices has led some members of the Canadian gas industry to call for government price supports. The introduction of price supports could lead to a situation where the price of natural gas falls considerably less than the price of oil. There is a reasonable likelihood that some government price supports could be introduced as have been in the past.

Ontario Hydro Cost Escalators

OM&A Labour Costs

15. Escalation for Operation, Maintenance and Administration (OM&A) labour rates is the average annual percentage change in total compensation. This includes wages and additional payments to employees and the cost of benefits paid by Hydro. The forecasts of Hydro's OM&A labour escalation for 1986 and 1987 (table 2-8) are at or slightly below the forecasts for the private manufacturing sector wages (table 2-7).

OM&A Other Costs

16. OM&A Other Costs consist primarily of materials, supplies, and purchased services. OM&A Other Costs escalation is expected to follow general inflation in 1986 and 1987. Escalation for OM&A Other Costs is presented in table 2-8.

Average hourly earnings — **Table 2-7**

Annual average % change	1985	1986	1987
Ontario			
Manufacturing	3.6	3.8	5.0
Construction	3.0	4.0	4.5
CPI-Toronto	3.9	4.2	4.5
Canada			
Manufacturing	3.5	3.8	5.0
Construction	1.8	4.0	4.5
CPI	4.0	4.0	4.5

OM&A escalation — **Table 2-8**

Forecast indices	1985	1986	1987
Total Labour costs	4.1	3.7	4.9
Other costs	3.1	3.6	4.7
Composite	3.9	3.7	4.9

Fuel Purchase Costs

17. Escalation rates for Hydro's fuel purchases are based on assumptions outlined in this chapter concerning various energy and economic price movements. Forecasts of fuel requirements by year and specific contractual conditions are also applied in forecasting the prices of individual fuels. Water rental price escalation is tied to the Canadian CPI. The forecast annual percentage change in prices for the major energy sources is discussed in chapter 4.

LOAD FORECAST

18. Primary sales are essentially all Ontario Hydro's electricity sales in Ontario.

19. Forecast primary sales are based on Load Forecast - 851209 (exhibit 2.1.16). This incorporates the Short-Term (previously called the Budget Load Forecast) and Long-Term Load Forecasts. The Short-Term Load Forecast, with a five-year horizon, was completed in August 1985, based partially on the customer demand forecast data gathered in April 1985. The Long-Term Load Forecast, with a 20 year horizon, was completed in December 1985.

20. Electricity sales forecasts are, like any forecast, ultimately dependent on judgment. The forecaster must take into account variables and their interactions. The analytical techniques which may be used range from historical analogy to complex quantitative models. In the Short-Term Load Forecast, the factors taken into account include the recent history of electricity sales; Hydro's customers' forecasts of future sales; and forecasts of variables including the level of economic activity, prices of electricity and competing fuels, and other relevant factors. The resulting electricity sales forecast is a central planning assumption for Hydro, and is used in the development of other Hydro projections.

21. The energy forecast in Load Forecast - 851209 is marginally higher than in Load Forecast - 841210 in all forecast years. In particular, the forecast of energy for 1987 is about 0.3% higher than the previous year's forecast. On the other hand, the peak forecast is lower than in Load Forecast-841210. For 1987 the December peak is approximately 1% lower than the previous forecast.

Primary sales* **Table 2-9**

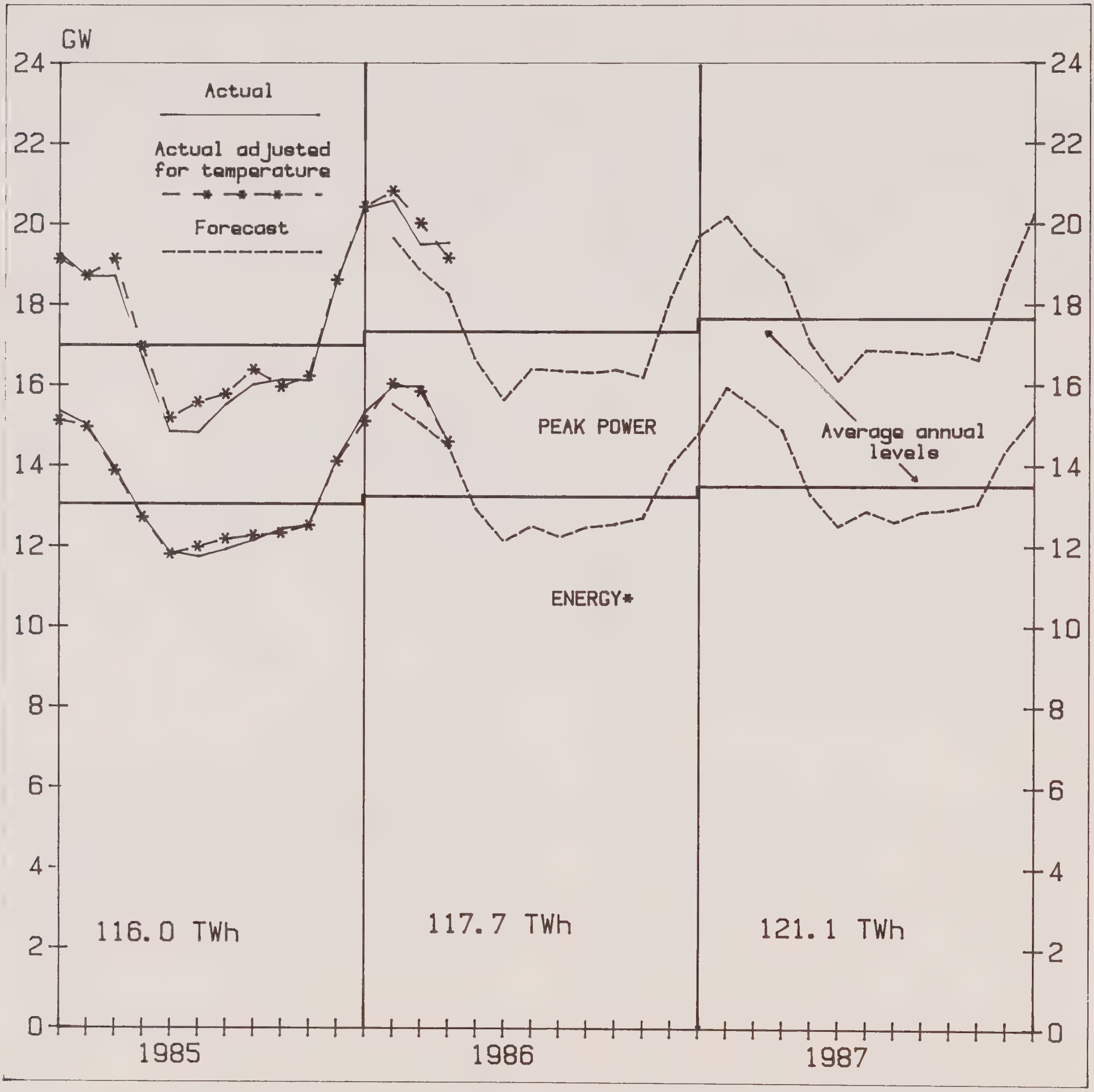
	1985	1986	**1987**
Peak power			
(average monthly - MW)	17 137	17 370	**17 855**
% growth	4.5	1.4	**2.8**
Peak (December - MW)	20 393	19 697	**20 245**
% growth	13.6	(3.4)	**2.8**
Energy (GWh)	116 049	117 719	**121 066**
% growth	3.3	1.4	**2.8**

* Total system primary demand

22. The small changes in forecast sales reflect the actual experience of 1984 and 1985. Actual energy sales in the first three quarters of 1984 and in the first quarter of 1985 were slightly above levels forecast in 1984, but in the second quarter the actual sales level is considered to be as forecasted. With the exception of the last quarter in 1985, peak sales have been below forecast levels. The higher than forecast levels for November and December, 1985 may be the result of stronger-than-expected performance of the Ontario economy. Load Forecast - 851209 assumes that the level of economic activity and electricity sales reached by the end of 1985 will form a base for continuing growth.

Load forecast - 851209 - total system primary demand: peak power and energy

Chart 2-10



* Monthly energy is given in GW-months (the number of GWh of monthly energy divided by the number of hours in the month) in order to show average demand levels in relation to peak demand levels.

Terminology

23. **System demand versus customer deliveries:** total system primary demand is essentially the total amount of electricity (peak power or energy) that Ontario Hydro must generate or purchase to meet the demands of Ontario customers. Customer deliveries are the total amount of electricity (peak power or energy) delivered to Ontario customers, as measured at the customers' wholesale billing points, and which form the basis for cost allocation and rate setting. Table 2-11 and paragraph 25 deal further with these quantities.

24. **Peak power versus energy:** peak power, often shortened to "peak" or "power", refers to the maximum rate of delivery of energy sustained over a brief interval of time ("the peak"). The values of peak power presented in this chapter are based on a 60-minute time interval, which is the basis for customer bills. Peak power is typically reported in megawatts (MW) or gigawatts (1 GW = 1000 MW). Energy is typically reported in gigawatt-hours (GWh) or terrawatt-hours (1 TWh = 1000 GWh).

25. Total system demands and total customer deliveries differ primarily because of transmission losses and, in the case of peak power, diversity. Diversity arises because individual customers will in general have their peak power consumption at "diverse" times, i.e., at times different from that of the system peak.

LOAD FORECAST – 851209

26. In chart 2-10, the forecast of monthly system peak power and energy demands is shown for 1986 and 1987 together with actual values for 1985. Also shown for 1985 are actual values adjusted for temperature, which give a clearer indication of the demand for electricity.

Forecast – customer delivered power and energy — **Table 2-11**

	1986	1987
Peak power (average monthly – MW)		
Municipal utilities	12 276	**12 570**
Rural customers	2 760	**2 839**
Direct customers	2 745	**2 872**
Total customer delivered power	17 780	**18 281**
Plus: internal sales	89	**87**
non-common losses	(20)	**(21)**
Total delivered power	17 849	**18 346**
Plus: diversity	(1 270)	**(1 306)**
transmission losses	791	**815**
Total system primary demand	17 370	**17 855**
Energy (GWh)		
Municipal utilities	78 094	**79 944**
Rural customers	15 643	**16 095**
Direct customers	18 819	**19 744**
Total customer delivered energy	112 556	**115 783**
Plus: internal sales	642	**633**
non-common losses	(89)	**(92)**
Total delivered energy	113 108	**116 324**
Plus: transmission losses	4 611	**4 742**
Total system primary demand	117 719	**121 066**

27. Table 2-11 relates the customer deliveries in Load Forecast - 851209 to total system primary demand. The adjustment made for internal sales and small non-common losses is also indicated. Internal sales include demands related to Hydro's use of electricity for the operation of the Bruce heavy water plant and for the construction of generating stations. Non-common losses reflect small adjustments made to all customer categories to allow for treatment of losses on transformation facilities and subtransmission lines.

Forecast Uncertainty

28. The forecast has an associated uncertainty, of which the most notable source in the short term is the unpredictability of weather. Other uncertainties include the course of the economy, labour disputes, and the extent of interfuel substitution. The forecast range of uncertainty corresponding to a 60% level of confidence for system demand is shown in table 2-12.

Forecast uncertainty **Table 2-12**

Range of uncertainty corresponding to a 60% level of confidence

	1986	1987
Peak power (GW)*	17.4 ± 0.3	**17.9 ± 0.7**
Energy (TWh)	117.7 ± 1.6	**121.1 ± 4.5**

* average monthly

Assumptions

29. The primary assumptions used in August 1985 to develop the 1985 Short-Term Load Forecast are the level of economic activity in Ontario, electricity price levels, and Hydro's demand-oriented programs.

Comparison of Economic Outlook

30. Load Forecast - 851209 assumes Ontario Gross Provincial Product (GPP) of $59.1 billion in 1987, as shown in the Economic Outlook - 1985 Spring Review (exhibit 2.1.4 from H.R. 14), up from a forecast of $58.4 billion made the previous year.

31. The Ontario economy has performed better than expected. Growth was higher in both 1984 and 1985 than had been forecast. At the time of the current load forecast, the Economics and Forecasts Division still expected a noticeable slowdown in the economy in 1986, with a renewed recovery in 1987. The slow growth in 1986 was expected to be caused by a faltering US economy and the elimination of import quotas on Japanese cars, which will weaken Ontario exports to the United States. Table 2-13 summarizes forecasts of Ontario's GPP.

Gross provincial product forecasts used in the short-term load forecast **Table 2-13**

$ billions (1971)

Forecast Date	Rate Proposal	1985	1986	1987
May-1984	1986	55.3	56.7	**58.4**
May-1985	1987	56.3	57.1	**59.1**

Electricity Price Levels

32. The 1985 Short-Term Load Forecast expected electricity prices to fall in real terms over the next few years.

33. The effect of electricity price decreases depends both on the level of prices and on their relation to prices of alternative fuels. The two fuels with which electricity competes most directly are natural gas and fuel oil. Temporary oversupply situations in both fuels will keep their prices falling in real terms over the next few years. The result will be a temporary increase in the price advantage that natural gas has over electricity, and a temporary decrease in the advantage that electricity has over fuel oil, in most markets.

Ontario Hydro's Marketing Programs

34. Hydro's marketing programs are designed to help manage electricity demand to optimize customer satisfaction, and ultimately to optimize the use of Hydro's existing and committed system. Depending on the level of autonomous demand relative to the capacity of the system, optimization may require efforts aimed, on balance, at increasing or at decreasing electricity sales. Because the programs promote wise use, some of them may reduce electricity sales through increased usage efficiency.

35. On balance, however, from 1986 to 1989, the marketing programs as directed by the Corporate Strategy are expected to produce loads above those which would otherwise occur. However, it is not possible to identify the exact amount of such an increase. The historical databases on which the forecast is based included some, probably small, effect of recent marketing efforts. Also, the regional estimates include information on the expected effect of the marketing program. Since both of these basic sources for the forecast already contain some unidentifiable effect of marketing, it is not possible to identify its exact effect in any forecast year.

FORECASTING PROCESS

36. The process for developing the forecast begins in early spring with a survey of customers' projected peak power conducted by regional staff. For each municipality, direct customer, and retail area an estimate is obtained for the current year plus an additional five years. These regional estimates are reviewed by the Load Forecasts Department for starting level, seasonal pattern, and growth. In the process of reviewing these regional estimates whenever they appear unduly high or low the regional staff is contacted to discuss and review the estimates with the customer.

37. The customers' energy forecast is then derived by multiplying the customers' peak power by the forecasts of the customers' load factor, based on historical data. Diversity and losses estimates are then forecast and applied to the total customer delivered power and energy to determine the preliminary total system primary demand. Primary energy demands are then compared against short-range forecasting models.

38. The forecaster must judge whether these preliminary total system primary demands reflect expected fluctuations in the economy in the current and next predicted business cycle. Considerations include expected short term disturbances such as strikes; construction plans of businesses and commercial developers; and expected energy prices. Energy prices are obtained from the Retail Energy Price Trends Report (exhibit 2.1.15). The resulting adjustment is known as unallocated load. In recent years unallocated load has been negative, indicating that the forecaster believes loads will be lower than the preliminary level.

Changes for 1986

39. No significant changes have occurred in the forecasting process or procedure. There have, however, been some changes in the short-term forecasting methodology. The Load Forecast Department has recently tested and implemented various short-range forecasting models, some of them using relatively new forecasting techniques. The techniques used most heavily were Box-Jenkins time series analysis, State-Space models, and Econometric Regression models.

40. System primary energy demand is estimated to be 0.4% higher in 1986 than the level forecast in the 1984 Budget Load Forecast (now called the Short-Term Load Forecast) and 0.3% higher in 1987.

41. The 1985 regional estimates of Hydro's customer forecasts were lower than those obtained for the 1984 Budget Load Forecast. The latest estimates are approximately 2% lower than the previous years' estimates for 1985 to 1987. The total of negative unallocated load has fallen from the 1984 Budget Forecast reflecting the downward adjustment made in the current customers' estimates.

SENSITIVITIES

42. In the short term, changes in the economic outlook affect all revenue requirement components except depreciation. Inflation in Canada affects OM&A costs through labour and material costs, and fuel and fuel-related costs through fuel price changes. Inflation in the US does not materially affect the revenue requirement; there may be minor offsetting impacts on the cost of US coal and revenues from secondary electricity sales. Changes in interest rates only slightly affect the revenue requirement. The effect of an interest rate increase on new debt issues and floating rate debt is largely offset by increases in interest capitalized and investment income, and a decrease in the amortization of foreign exchange losses. Foreign exchange rates affect interest and foreign exchange costs through the interest costs on foreign debt and the amortization of foreign exchange losses, and also affect secondary revenues and US coal purchases.

43. An increase in the volume of primary sales will increase the fuel and fuel-related component of the revenue requirement, but generally this will be more than offset by the increase in primary revenues, for an overall favourable impact on either the required rate increase, or net income. The estimated effect of a one percentage point growth in primary sales is shown in table 2-14. This effect is calculated based on assumptions that the increase occurs proportionally in both peak power and energy and is distributed proportionally across all customer categories.

44. The sensitivity of financial results to changes in the economic outlook and primary sales, each presented individually, is presented in table 2-14. All sensitivities provided should be regarded as basic rules of thumb since simplifying assumptions have been used in their development. For example, the sensitivity to inflation has been developed from historical trends. Results of using these rules should be considered approximate at best, since no consideration has been given to the validity of extrapolation, or the potential interrelationships that exist.

45. Generally, the sensitivity of financial results to a change in a planning assumption may be presented either as an uncertainty in revenue requirement, assuming an unchanged level of net income, or as an uncertainty in net income assuming an unchanged level of rates.

46. In this submission the former approach is used. This choice is purely one of convenience of presentation and should not be taken to imply that net income would remain unchanged in response to a changed planning assumption.

Sensitivity of revenue requirement in 1987 — **Table 2-14**

	Assumed variation	Revenue requirement impact ($ millions)	Rate increase impact (% points)
Economic variables			
CPI-Canada	+1% pt	+11	+0.2
Interest rates	+1% pt	+ 5	+0.1
Canadian dollar	+1 US	-31	-0.7
Primary sales			
Volume	+1% pt	+27	-0.5

Chapter 3
MARKETING

1. Ontario Hydro's marketing strategy supports the Corporate goal of meeting the requirements of the Ontario community for a safe, reliable supply of electricity at lowest feasible cost over the long term. The marketing strategy also supports the Corporate strategy to reorient Hydro for a slow growth environment, to respond to customer needs, and to foster selected activities which use Hydro's special capabilities to produce revenue. Corporate objectives include customer satisfaction, reasonable rates, flexibility and responsiveness. Marketing contributes to these objectives through customer-oriented programs.

2. Marketing efforts aim at satisfying customer needs. This includes providing programs which will improve customers' ability to manage energy use wisely. Marketing can be defined as managing the demand side of the Corporation, and balancing customer needs with Ontario Hydro's ability to supply these needs in a changing market environment. Marketing allows Ontario Hydro to interact with cutomers to determine their needs and also influence customer demand and load shape to better match existing and committed supply capabilities.

3. One of Hydro's corporate goals is to attempt to keep increases in the price of electricity during the 1980s at or below the inflation rate for the decade.

4. Marketing of electricity can help make better use of existing and new generating capacity, and therefore help keep down the price of electricity.

5. Ontario Hydro divides the energy market into the industrial, commercial, agricultural, transportation, and residential sectors. Hydro recognizes that wise energy management can and will vary according to customer needs, financial situation and location.

6. The short term marketing strategy (to 1990s) is to build load selectively with a moderate marketing investment while continuing to convey the importance of efficient energy use. In order to ensure that the long term demand/supply issues are addressed, the strategy also includes the introduction of load management, strategic conservation and cogeneration programs as needs arise.

7. In the commercial and industrial sectors, programs are aimed at identifying electrical and energy management opportunities for customers to improve operating efficiencies and overall productivity and to reduce costs. In the residential sector, information on improved energy efficiency as well as added flexibility and home comfort are provided to homeowners.

8. A comprehensive process for developing marketing programs was established in 1985. For each program, a goal is formulated, current and expected future conditions analyzed, measurable objectives and standards established, alternative strategies and tactics considered, and the program is documented with specific targets against which success is measured. In general, marketing programs include objectives such as improved productivity, energy efficiency, reduced customer costs, increased service satisfaction, greater customer awareness, improved load manageability, as well as load growth.

9. Marketing efforts will promote some growth in peak demand but not all programs will add to peak. For instance, add-on heat pumps are typically off-peak devices. Studies are also underway to develop future marketing programs which will reduce peak demand (e.g. water heater load control) as they are required.

10. Hydro's mandate is to provide power at the lowest feasible cost over the long term to the province's electricity customers. In order to do this, Hydro treats all customers, whether residential, commercial or industrial, in an equitable manner. Last year Ontario Hydro received OEB agreement to test a number of different rates for large industrial customers. Also, rate studies addressing time of use rates and other incentive rates are being carried out and will allow greater rate flexibility and load shaping capabilities in the future.

11. Ontario Hydro works with municipal utilities to achieve its marketing objectives in several ways. By meeting with utilities at district marketing committee meetings, both Ontario Hydro and the utilities can exchange information and views on marketing related matters. Regional staff meet with individual utility personnel to discuss program implementation. Flexibility is included in most programs to allow a custom fit to meet the unique requirements of an individual utility. Head Office personnel participate in the utility association's marketing committees to discuss general aspects of policy and direction.

12. Further details on Hydro's marketing strategy and programs are contained in exhibits 3.1.2, Strategic and Policy Issues; 3.1.3, Market Planning Process; 3.1.4, Marketing Branch Electricity Programs; 3.1.5, Marketing Costs; 3.1.6, New Business Ventures.

Chapter 4
FUEL AND FUEL-RELATED AND SECONDARY SALES

FUEL AND FUEL-RELATED

1. Fuel and fuel-related costs are costs of fuel used for electric generation, water rentals, costs of purchased electricity, and expenses or credits associated with the Pickering Payback Agreement. Fuel and fuel-related costs vary with the amount of electricity supplied.

Fuel and fuel-related – revenue requirement — **Table 4-1**

$ millions	1985	1986	1987
Fuel and fuel-related			
Fuel used for electric generation			
Fossil	**782**	**640**	**558**
Nuclear	**221**	**300**	**358**
Internal transfers	**[35]**	**[21]**	**[26]**
	968	**919**	**890**
Water rentals	**87**	**91**	**94**
Power purchased	**163**	**121**	**72**
Payback	**[75]**	**[62]**	**34**
	1143	**1069**	**1090**
OM&A	966	1036	1120
Fixed charges	2156	2471	2728
Net income	360	301	294
Secondary power and energy	[351]	[349]	[360]
Revenue requirement	4274	4529	4873
	====	====	====

ELECTRICITY PRODUCTION

2. The amount of electricity supplied from each of the resources, shown in table 4-2, depends upon several factors, including

- primary energy demand in Ontario;
- hydraulic conditions;
- availability of economically attractive electricity from external systems;
- performance of Ontario Hydro's generating units;
- the level of secondary sales.

3. The values in table 4-2 are based on the Addendum to Consistent Energy Set 86-1 [exhibit 4.1.6]. Further elaboration on several of the topics addressed in this chapter can be found in exhibits 4.1.4, Status of Selected Fuel & Fuel-Related Matters, 4.1.5, CES 86-1, and 4.1.6, Addendum to CES 86-1.

Nuclear

4. In 1987, electricity production from in-service nuclear units is forecast to be approximately 18% higher than the value currently forecast for 1986. This is the result of the full year impact of units which were placed in-service in 1986 [Pickering B Unit 8 and Bruce B Unit 7] plus new production from Bruce B Unit 8 to be placed in service during 1987 and from Pickering A Units 1 and 2.

Hydraulic

5. Energy production from hydraulic resources depends mainly on natural runoff. In 1987, hydraulic production is forecast to decrease by approximately 2% from the value expected for 1986. Median conditions are forecast for all eastern watersheds except for the Niagara and St. Lawrence Rivers. For these rivers, which reflect relatively high Great Lakes levels, and the West System watersheds, conditions are forecast to continue somewhat above normal in 1987.

Electricity production Table 4-2

GWh	1985	1986	1987
Nuclear			
Pickering	16 984	21 878	29 055
Bruce	30 861	36 706	40 208
NPD	110	135	142
	47 955	58 719	69 405
Hydraulic			
East System	32 939	32 944	32 663
West System	4 485	4 578	4 138
	37 424	37 522	36 801
Fossil			
Coal	29 829	22 498	19 166
CTU	9	24	13
	29 838	22 522	19 179
Commissioning	606	954	356
External resources			
Purchases	8 746	6 811	4 378
Net other interchange	44	179	251
	8 790	6 990	4 629
Total resources	124 614	126 707	130 370
Secondary electricity sales			
Firm	3 895	4 123	4 125
Interruptible	4 670	4 530	5 179
	8 565	8 653	9 304
Total system primary demand	116 049	118 054*	121 066

* Includes January actuals

Fossil

6. Fossil generation is the most expensive major resource. It is the swing resource which balances loads and generation and reflects the net change in the other variables. In 1987, fossil production is forecast to be some 15% below the values expected for 1986. This decrease is due to the substantial increase in nuclear production, partially offset by the combination of increased primary demand and secondary sales, reduced volumes of purchased energy and reduced hydraulic production. The forecast level of fossil production will result in acid gas emissions below legislated limits.

Commissioning

7. In 1987, commissioning energy is expected to decline to approximately 35% of the amount produced in 1986. Bruce B Unit 8 is the only unit forecast to produce commissioning energy in 1987, completing a schedule expected to begin in 1986. Bruce B Unit 7 and Pickering B Unit 8 also contribute commissioning energy in 1986.

FUEL PRICES AND PURCHASES

Unit fuel cost escalation **Table 4-3**

Annual average % change

	1985	1986	1987
Coal			
US coal	5.1	(0.8)	2.4
W. Cdn coal	7.7	1.1	3.9
Lignite	7.1	(1.4)	3.5
Nuclear fuel			
28- element	26.2	(4.2)	(1.6)
37- element	18.3	(5.1)	0

8. The changes in average US coal prices shown in table 4-3 incorporate the impacts of the movement toward a lower average sulphur level, changes in the value of the Canadian dollar, and declining volumes over the period. Individual contract prices are forecast to increase more slowly than inflation due to a depressed coal market continuing into the foreseeable future. The 1985 price increase was greater than anticipated due to the value of the Canadian dollar being below forecast. In 1986, prices decline or remain constant, while small increases are forecast for 1987.

9. The price increase for Western Canadian coal was above inflation in 1985 because increased volumes purchased at lower incremental prices in 1984 were not repeated in 1985. A flat delivery pattern and expected price increases at less than the inflation rate, will result in unit price increases being lower than general inflation for 1986 and 1987.

10. Lignite prices in 1985 were also affected by delivery reductions from the 1984 level, and lower than forecast heat content. Lower price increases coupled with more lignite being shipped to Atikokan produce relatively minor price increases during the forecast period. Transportation costs are lower for deliveries to Atikokan compared to Thunder Bay.

11. In 1986 and 1987, finished nuclear fuel prices will decrease from the 1985 price levels. This is primarily due to the addition of lower cost contracts for uranium concentrate from Western Canadian suppliers and lower estimates for fabrication costs. These factors more than offset the impact of inflation over this period.

12. Total expenditures for fuel purchases, shown in table 4-4 are forecast to decline between 1985 and 1987. The increased amount of lower cost nuclear fuel in the mix, as coal generation is replaced by new nuclear generation, is expected to cause this reduction in total costs. Coal deliveries decline from 11.2 million tons in 1985 to 8.6 million tons in 1987, while nuclear fuel deliveries increase from 920 megagrams (U) to 1450 megagrams (U) during the same period.

Expenditures for fuel purchases **Table 4-4**

$ millions

	1985	1986	1987
Expenditures			
Fossil	753	622	**600**
Nuclear	247	280	**365**
Total	1001	902	**965**

FUEL AND FUEL-RELATED - REVENUE REQUIREMENT

13. The revenue requirement attributable to each of the components of fuel and fuel-related costs are shown in table 4-1. The changes in these costs from the previous year are shown in table 4-5.

Fuel and fuel-related - changes **Table 4-5**

$ millions change from previous year

	1986	1987
Fuel used for electric generation		
Fossil	(142)	**(82)**
Nuclear	80	**58**
Internal transfers	14	**(5)**
	49	**(29)**
Water rentals	4	**4**
Power purchased	(42)	**(49)**
Payback	13	**96**
Total	(74)	**21**

Fuel Costs

14. The revenue requirement for fossil and nuclear fuel is derived from the projected average cost of fuel consumed from station inventories. The forecast average unit cost of fuel in inventory takes into account the cost of fuel to be delivered to the generating stations.

15. The revenue requirement for fuel used for electric generation is forecast to decrease by $29 million in 1987. This is due to the shift from fossil-fuelled generation to nuclear-fuelled generation partly offset by increased sales volumes and moderately higher unit coal costs.

Fossil

16. Coal costs, the main component of fossil fuel costs, include charges for US coal, western Canadian coal and lignite taken from generating station inventories. Fossil fuel costs reflect the cost of downsizing below minimum contract quantities. Fossil fuel costs decrease by $82 million in 1987 mainly because of an expected 15% decrease in fossil-fuelled generation, partly offset by a 2% increase in unit costs. The revenue requirement attributable to fossil fuel in 1987 is $558 million.

Nuclear

17. Nuclear fuel costs are the costs of fuel used at Pickering and Bruce, including a charge for the ultimate disposal of irradiated nuclear fuel. The increased nuclear fuel costs in 1987 are related to increased generation from units placed in service in 1986 and 1987, Pickering A Units 1 and 2 which return to operation, and higher unit nuclear fuel costs in 1987. The revenue requirement attributable to nuclear fuel costs in 1987 is $358 million which includes $39 million for irradiated fuel disposal. This includes $0.1 million for disposal of fuel irradiated prior to 1987.

18. NPD costs are costs for steam purchased from Atomic Energy of Canada Limited (AECL), which owns the Nuclear Power Demonstration (NPD) reactor. The steam is used to power generating facilities owned by Hydro on the site. The price paid for steam is related to unit coal costs. An increase in costs to $9 million is due to escalation in the price of coal.

Internal Transfers

19. Internal transfers consist of the credit for internal sales, the Bruce steam transfer credit, and the charge for commissioning energy.

20. Internal sales represent Hydro's use of electricity for operating the Bruce heavy water plant and constructing generating stations. Internal sales are costed at the rate allocated to distributors for equivalent conditions of service, less the provision in rates for net income and customer administration. The credit for internal sales is forecast to be $22 million in 1987, a $1 million increase from 1986.

21. The Bruce steam transfer credit is an adjustment for the cost of supplying steam from Bruce A to the Bruce Heavy Water Plant and other loads. The credit is designed to ensure that the cost to current electricity customers is unaffected by the diversion of steam, a portion of which could have been used to generate electricity for the Bulk Electricity System (BES).

22. In 1987, the overall requirement for steam for the production of heavy water is reduced slightly from 1986, brought about by the decline in heavy water production. At the same time, larger amounts of locked-in energy at the Bruce site and higher reactor steam ratings cause an increase in the amount of steam which can be produced without reducing electricity production. These factors result in a lower credit, which is forecast to be $13 million in 1987.

23. The value of commissioning energy represents the additional cost that would have been incurred if an equal amount of energy had been produced by generation already in service. This value is credited to the capital cost for the commissioning unit and is charged to current operations as fuel used for electric generation. This treatment of the commissioning charge is designed to ensure that the cost to current electricity customers is unaffected by the amount and timing of commissioning activity.

24. Commissioning energy in 1987 will be provided by Bruce B Unit 8. The charge for commissioning energy is forecast to be $8 million in 1987, a $10 million decrease from 1986.

Water Rentals

25. Water rentals are paid to the Province of Ontario and to others for the use of water to generate electricity.

26. Although hydraulic production declines over the forecast period, water rental payments increase primarily because of the escalation clause in the agreements with the Province. The revenue requirement attributable to water rentals in 1987 is $94 million. The agreements with the Province of Ontario account for approximately 98% of the rental payments.

POWER PURCHASED

27. Power purchased is made up of external resource and other interchange and is shown in table 4-6.

External Resource

28. The forecast 1987 decrease of $49 million in the total cost of external resource purchases results from decreased volume, offset somewhat by increased average price.

Power purchases **Table 4-6**

	1985 GWh	1985 $M	1986 GWh	1986 $M	1987 GWh	1987 $M
External resource						
Contract	2500	56	2000	46	—	—
Secondary	6246	107	4811	74	4378	71
Total external resource	8746	163	6811	120	4378	71
Other interchange	44	1	179	1	251	1
Total	8790	163	6990	121	4629	72
Change from previous year	578	14	(1800)	(42)	(2361)	(49)

External resource - contract

29. Contract purchases from Hydro-Quebec are expected to conclude in 1986, with the delivery of the final 2000 GWh of the 12 500 GWh contract which covers the period from April 1982 through March 1987.

External resource - secondary

30. Total secondary purchases including other interchange in 1987 are expected to decrease by 7.2% (361 GWh) from the 1986 level. The amount of energy which can be purchased economically to displace fossil-fuelled generation on the Hydro system depends on the availability of surplus energy in Quebec and Manitoba and is affected by the amount of coal Hydro has under contract and in inventory. The forecast of secondary purchases is the amount of energy which can be purchased at prices which are economic.

31. No energy purchases are forecast from US sources in 1987 because running costs in the US are usually higher than those in Ontario.

Other Interchange

32. Besides the purchase and sale of electricity, there are special exchanges and adjustment transfers. These items, collectively called "other interchange", include carrier transfers and exchanges of electricity.

Pickering Payback Agreement

33. The payback results from the Pickering Payback Agreement between Hydro, AECL, and the Province of Ontario. Exhibit 1.1.20 (Summary of Major Contracts) provides a description of the elements included in the calculation of payback, and the history and status of current significant disputes over the interpretation of the Agreement, namely negative payback and irradiated fuel disposal costs.

34. The expected increase in payback from a negative value of $62 million in 1986 to a positive value of $34 million in 1987 reflects the completion of retubing and the return to full operation of Pickering A Units 1 and 2 in early 1987. The increase in nuclear fuel cost plus interest and depreciation on capital costs of retubing is more than offset by the increase in the value of energy produced. A detailed calculation of the AECL and Province share of payback is shown in table 4-7. Exhibit 4.1.11, Pickering Payback Variance Analysis contains a detailed calculation of payback and an analysis of changes in payback expense from last year's hearing.

Payback – AECL and province share **Table 4-7**

$ millions

	1985	1986	1987
Value of power	2	1	**3**
Value of energy	–	3	**126**
	2	4	**129**
Less:			
Electricity production costs			
Pressure tube			
removal provisions	47	29	**13**
capital retirement			
costs*	–	–	**23**
Irradiated fuel disposal	1	1	**3**
Other	26	36	**56**
	73	66	**95**
Year end adjustments	(4)	–	–
Payback	(75)	(62)	**34**

* For tube installation only

SECONDARY SALES

35. Table 4-8 shows revenues for secondary power and energy (gross revenue from secondary sales) in relation to the other components of the revenue requirement.

Revenues for secondary power and energy – revenue requirement **Table 4-8**

$ millions

	1985	1986	1987
Fuel and fuel-related	1143	1069	1090
Operation, maintenance and administration	966	1036	1120
Fixed charges	2156	2471	2728
Net income	360	301	294
Revenue for secondary power and energy	**(351)**	**(349)**	**(360)**
Revenue requirement	4274	4529	4873
	====	====	====

36. Ontario Hydro's secondary revenue is derived almost entirely from export sales of surplus power and energy. Hydro's policy on the export of surplus electricity is

- to provide emergency assistance to the maximum extent deemed consistent with the safe and proper operation of its own system, and with its prior obligations to other Canadian systems;

- to take advantage of opportunities for profitable sales at times other than emergencies in such quantities as deemed desirable having due regard for conditions on the Hydro system;

- to obtain a fair and economic return for the services provided, and to maximize the longer-term economic gain to Ontario, taking into account all applicable costs incurred in Canada and having due regard to the possibility that Hydro may need to purchase in future under the same conditions; and

- to adhere to the Corporation's policies on the conservation of energy and to any applicable governmental rules and regulations, including those relating to the use of resources, environmental restrictions, priority of supply and quantities that may be exported.

37. All secondary sales are interruptible if necessary to supply Ontario firm demands.

38. The level, prices, and revenues for secondary sales are presented in table 4-9. Also presented are the secondary sales cost and the estimated reduction in revenue requirement.

Secondary sales **Table 4-9**

	1985	1986	**1987**
Energy (GWh)*			
New York	8076	8181	**8300**
Michigan	485	468	**1000**
Total sales to US	8561	8649	**9300**
Average price ($/MWh)*	40.9	40.2	**38.6**
Gross revenue ($M)	350	348	**359**
Secondary sales cost ($M)	205	221	**220**
Reduction in revenue requirement ($M)	146	128	**140**

* Volume and price values exclude the impact of miscellaneous Ontario and other deliveries.

39. The secondary sales cost is an estimate of the cost including fuel, maintenance and inventory carrying costs required to generate the electricity for secondary sales. The estimated benefits to Ontario Hydro primary customers in the year of the sale is obtained by deducting the costs from revenues. Exhibit 4.1.23, Accounting Costs of Secondary Sales provides further details.

REGULATORY ENVIRONMENT

40. The regulatory environment in the United States and Canada has an effect on Hydro's export sales. US regulation involves both policies related to imports from Canada as well as policies which affect the cost of generation and the financial health of US utilities. In Canada, approvals of exports are primarily regulated by the National Energy Board. Exhibit 4.1.18, Regulatory Environment Report discusses this in more detail.

MARKETING ENVIRONMENT CHANGES SINCE JULY 1985

41. Since July 1985, a number of American coal-fired plants and some new transmission projects have proceeded approximately on schedule. The status of new nuclear stations has been less predictable. Exhibit 4.1.17, Market Environment Report provides further detail, under the following headings: load forecast, status of plants under construction, new transmission environment, and fuel prices.

RESOURCE AVAILABILITY IN THE POTENTIAL MARKET

42. The major power pools and utilities operating in and influencing Hydro's market area are

- New England Power Pool (NEPOOL);
- New York Power Pool (NYPP);
- Pennsylvania - New Jersey - Maryland (PJM);
- Central Area Power Coordination Group (CAPCO);
- Michigan Electric Coordinated System (MECS);
- American Electric Power System (AEP); and
- Allegheny Power System (APS).

43. Exhibit 4.1.17, Market Environment Report illustrates the geographic location of these power pools and utilities. The anticipated load and capacity situation during summer 1987 and winter 1987/1988 is also summarized. The level of reserve above projected peak load identified in these figures indicate that these utilities and power pools have adequate levels of capacity reserves. Oil capability in New England and New York demonstrates the availability of oil displacement markets in these areas.

TRANSMISSION IN THE MARKET AREA

44. Exhibit 4.1.19, Transmission in the Market Area describes Ontario Hydro's interconnections with its neighbouring utilities. Also discussed are the transmission bottlenecks in the market area both internal and external to Hydro. As discussed in greater detail, these bottlenecks represent potential limitations to Hydro's sales capability.

COMPETITION IN THE MARKET AND ONTARIO HYDRO RESPONSE

45. Hydro-Quebec is Ontario Hydro's main competitor for sales in the New York and New England market area. New Brunswick Power is also a major supplier to New England. Among US utilities, Ontario Hydro's primary competitor is the Ohio-based AEP, which sells heavily to utilities to the south and to the west of Ontario. Exhibit 4.1.20, Competition in the Market describes in more detail the practices of these utilities who represent Hydro's chief competition and Hydro's response to that competition.

SENSITIVITY OF REVENUE REQUIREMENT AND RATE INCREASE TO SECONDARY SALES

46. Table 4-10 provides the estimated sensitivity of revenue requirement and the rate increase to changes in price and volume of secondary sales. A change in volume from the forecasted level affects both secondary revenues and fuel costs, while a change in price affects secondary revenues only.

Sensitivity of revenue requirement and rate increase to secondary sales — **Table 4-10**

	Assume Variation	Revenue Requirement Impact ($ million)	Rate Increase Impact (% points)
Volume	+500 GWh	-8	-0.2
Price	+1%	-4	-0.1

Chapter 5
OPERATION, MAINTENANCE AND ADMINISTRATION

1. Operation, maintenance and administration (OM&A) costs consist of OM&A program costs and other costs and adjustments.

Operation, maintenance and administration – revenue requirement **Table 5-1**

$ millions

	1985	1986	1987
Fuel and fuel-related	968	919	890
Operation, maintenance and administration	**966**	**1036**	**1120**
Fixed charges	2156	2471	2728
Net income	360	301	294
Secondary power and energy	(351)	(349)	(360)
Revenue requirement	4274	4529	4873

2. OM&A program costs are the costs of

- operating and maintaining all generating stations, transmission lines and stations, and distribution facilities;
- administering these activities from head office, and regional, area, and facility offices;
- providing marketing and customer support services; and
- planning work on existing and future power system facilities.

3. Other costs and adjustments are expenditures and credits which are not allocated to specific programs. Other costs include payments in lieu of property taxes, certain cancelled and rescheduled project costs, and other corporate expenditures. Adjustments are for overheads capitalized and recovered, and a credit for indirect depreciation.

4. The presentation of actual 1985 costs in table 5-2 reflects the organizational structure as of March 1986. The 1986 and 1987 OM&A program costs are based on program budget costs contained in the approved 1986 Corporate Budget (exhibit 5.1.18) updated for a $20 million change in the corporate adjustment. 1987 OM&A costs have also been updated to reflect the corporate impact of the February 1986 cost escalators and a one month delay in Bruce Unit 8 in-service. Dollar amounts in the discussion which follows are expressed in 1986 dollars (September 1985 Cost Escalators).

Corporate Budget Review Process

5. OM&A cost levels for 1987 were developed through the 1986-1987 budget process. Chart 5-3 shows the key events and timing of the budget process followed. Corporate Programming Guidelines for 1986-1987 were issued by the President in July 1985 for use by the branches in the preparation of their work program budgets. The budgets submitted by the branches in October 1985 were generally consistent with these guidelines.

6. During the budget review process, potential reductions and work program requirements were assessed by the Budget Review Committee and reviewed with the branch vice-presidents, the executive vice-presidents, and the Senior Executive Vice-President. The 1987 OM&A cost levels, as contained in the 1986 Corporate Budget, are $14 million lower than the originally submitted budgets. This was mainly as a result of a subsequent decrease in the burden rate made possible by an increase in the projected pension fund surplus.

Operation, maintenance and administration Table 5-2

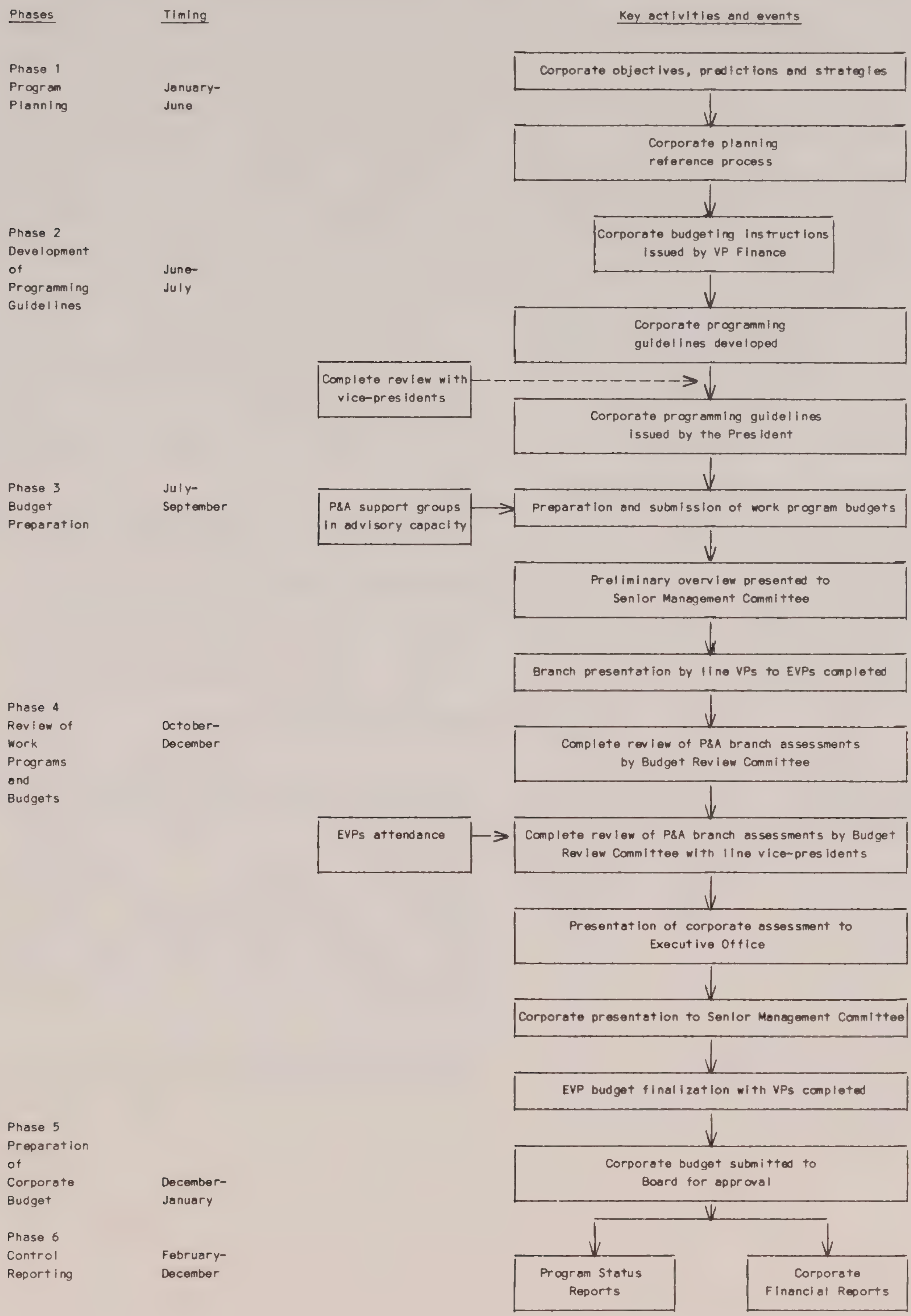
$ millions

	1985	1985	1986	1987	1987
	(1985$)	(1986$)			(1987$)
OM&A program costs					
Operations					
Production	474	493	518	562	595
Regions	277	289	284	282	302
Marketing - Electricity	27	28	33	36	37
- Related Business	(2)	(3)	(6)	(9)	(9)
	775	807	830	871	924
Engineering and Services					
Design and Construction	34	36	40	38	40
Supply and Services	56	57	60	57	60
	90	93	100	95	100
Planning and Administration					
Power System Program	42	43	44	43	45
Human Resources	26	26	27	28	29
Finance	27	28	27	26	28
Corporate Relations	8	9	8	8	8
	102	106	106	105	110
Executive, Secretariat, Law, and Audit	17	17	17	16	17
	984	1022	1053	1087	1152
Program cost adjustments					
Corporate adjustment	-	-	(5)	(5)	(5)
Payroll adjustment fiscal to calendar year	2	2	3	3	3
Surplus staff	2	2	3	3	3
	5	5	1	1	1
OM&A program costs	989	1027	1054	1087	1153
Other costs and adjustments					
Overheads capitalized and recovered	(48)	(49)	(44)	(41)	(43)
Indirect depreciation	(26)	(26)	(28)	(32)	(32)
Payments in lieu of property taxes	33	35	37	38	40
Cancelled and rescheduled project costs	1	1	1	2	2
Other corporate expenditures	16	17	17	17	18
	(23)	(22)	(18)	(16)	(15)
February 1986 Cost Escalator Impact	-	-	-	(4)	(18)
Operation, maintenance and administration	966*	1005	1036	1068	1120

*. 1985 actual costs for the Marketing Branch and Regions Branch have been normalized to reflect the 1986 organization structure

. 1985 actuals have been normalized to reflect the 1985 corporate burden adjustments at the program level

Budgeting process **Chart 5-3**



7. Subsequent to the approval of the 1986 Corporate Budget, the Branch year-end figures for 1985 were determined. The actual costs revealed that the budgeted corporate adjustment of $25 million did not fully materialize. This information, coupled with already tight Branch budgets, led to a decision to reduce the projected corporate adjustment from $25 million to $5 million. This results in an increase in projected OM&A costs of $20 million in each of 1986 and 1987.

Analysis of Changes in OM&A Program Costs

8. Table 5-4 summarizes the changes in OM&A program costs in 1986 compared to 1985 actuals, and costs in 1987 compared to 1986.

OM&A program costs - changes **Table 5-4**

$ millions change from previous year

	1986	1987
Program change (1986$)		
Work program change	32	**33**
Corporate adjustment	(5)	**0**
	27	**33**
Escalation	38	**66**
Total	65	**99**

9. Real growth in OM&A program costs is budgeted to be 3% in both 1986 and 1987. The significant items of real cost change in 1987 are summarized in table 5-5.

OM&A program changes **Table 5-5**

1986 $ millions	1987
. increased generating unit months of operation and other facilities	28
. decreased payroll burden	(15)
. return to operation of Pickering Units 1 & 2	9
. increased cost of heavy water make-up	8
. miscellaneous program changes	3
Total	33

1987 vs 1986 OM&A Program Changes

10. The increase in generating unit months of operation and associated support activities relates to Bruce Unit 8 coming into service in 1987 and the full-year impact of Pickering Unit 8. Together these represent an increase of 15 unit months of operation over the 1986 base of 176 unit months of operation at Pickering and Bruce. Associated support activities include items such as field support services, training and heavy water upkeep costs. Other facilities include heavy water upgrading.

11. The most recent reviews and valuations of the Pension Fund indicate that the total funds available to reduce 1987 OM&A costs will be $63 million, as compared to $44 million for 1986. This will decrease OM&A program costs by $19 million, while other changes in payroll burden will increase costs by approximately $4 million. It should be noted that the accounting treatment associated with pension funds is currently under review.

12. Pickering Units 1 and 2 are forecast to return to operation in February and May 1987 respectively. Resources previously deployed on capital projects will now return to operation. This shift will increase OM&A program costs by $5 million. In addition, the operation of Pickering Unit 1 and 2 will increase heavy water losses by $4 million.

13. The unit cost of heavy water is forecast to increase as a result of a 25% decrease in heavy water production with no corresponding decrease in interest and depreciation charges. The impact on OM&A program costs is an increase of $8 million in 1987.

14. Miscellaneous program changes refers to a number of offsetting branch work program changes.

Analysis of Changes in OM&A Other Costs and Adjustments

15. Other costs and adjustments are forecast to increase by $2 million in 1987 mainly because of

- a decrease in the credit for overheads capitalized and recovered;
- an increase in payments in lieu of property taxes;
- an increase in cancelled and rescheduled project costs; and
- an offsetting increase in indirect depreciation credit adjustments.

Human Resources

16. Staff levels are shown in table 5-6 covering both OM&A and capital programs. The forecasted year-end level of regular staff (excluding staff on surplus payrolls) for 1987 represents no change from the 1986 level and an increase of 282 from the 1985 year-end actual. Non-regular staff requirements are planned to decrease by 17% in 1986 from 1985 levels and decrease by 14% in 1987 compared to 1986.

Staff levels Table 5-6

	1985	1986	1987
Regular staff (year-end)*	23 108	23 388	**23 388**
Regular staff on surplus payrolls (year-end)	10	12	**12**
Non-regular staff 1,000's of hours	14 194	11 724	**10 035**

* Excluding staff on surplus payrolls

17. Regular staff levels are expected to remain constant through 1987; essentially all planned increases in regular staff levels are in the Operations Group and are related primarily to new generation facilities, marketing programs, and the Arbitration Award on specific staff ratios resulting from 1985 bargaining with the OHEU. Most of the change in the requirement for non-regular staff is related to the decreasing need for casual construction staff in the Design & Construction Branch.

18. There will be some reallocation of staff among branches required. This results primarily from continuing downsizing in the Engineering and Services Group, and growth in the Operations Group. The surplus redeployment rate is expected to continue to be very high during 1986 and 1987.

Chapter 6
CAPITAL PROGRAM AND BORROWING REQUIREMENT

1. Capital program costs, which include interest capitalized, represent the cost of

- providing and modifying facilities for generation, transmission and distribution of electricity;
- providing facilities and equipment for service and administration; and
- providing heavy water and financing heavy water inventory.

2. Investment in fixed assets is made up of the costs of the capital program, less adjustments primarily for capitalized depreciation and fixed asset removal expenditures.

Capital program costs **Table 6-1**

$ millions

	1985 Actual	1986	1987
Capital program costs			
Generation			
Nuclear	1 775	1 779	**1 316**
Fossil	100	15	**3**
Hydraulic	15	17	**18**
Heavy water	342	301	**255**
Transmission/distribution	113	288	**401**
Rural distribution	143	142	**153**
Administration/service	117	141	**107**
Total capital program costs	2 605	2 683	**2 252**
Adjustments	(64)	(141)	**(103)**
Investment in fixed assets	2 541	2 542	**2 149**

3. The capital program costs shown in table 6-1 are consistent with financial in-service dates used to develop the financial results contained in the rate proposal. These dates differ slightly from the corporation's currently approved in-service dates, as discussed in exhibit 6.1.2, Capital Construction Program In-Service Date Assumptions.

4. For Bruce Unit 8, the financial in-service date of February 1987 incorporates a one-month slippage from the approved date. For Pickering Units 1 and 2, the financial return to operation dates of February and May 1987 incorporate three-month slippages from the approved dates.

5. With the completion of Pickering B in early 1986 and Bruce B in early 1987, capital program costs decrease by about $430 million in 1987 relative to 1986. Darlington expenditures, which account for 88% of nuclear generation expenditures in 1987, are expected to decrease marginally from 1986.

6. Heavy water inventory costs in 1987 are expected to be approximately $46 million lower than in 1986 because of decreasing future use inventory levels as heavy water is assigned to new nuclear units. Heavy water future use inventory levels will be increased beyond 1987 to meet Darlington Units 3 and 4 requirements.

7. Transmission and distribution costs are expected to increase by $113 million in 1987. A major portion of the forecast transmission program is related to the 500 kV lines under construction from Hanmer TS to Mississagi TS and from Bowmanville SS to Cherrywood TS as well as the supply to Eastern Ontario for which Ontario Hydro is seeking Governmental approval. Transmission costs in 1987 also include planned expenditures on the second 500 kV line out of Bruce, expected to be in-service in 1989.

8. The borrowing requirement mainly represents the requirement for funds to finance the capital program and to retire debt, less funds provided by operations, as shown in table 6-2.

Borrowing requirement **Table 6-2**

$ millions

	1985 Actual	1986	**1987**
Investment in fixed assets	2541	2542	**2149**
Debt retirement			
Maturities	849	394	**1053**
Premature retirements	175	208	**85**
Changes in other assets and liabilities	(596)	(130)	**133**
Total	2969	3014	**3420**
Less: funds from operations	1175	1156	**1320**
Borrowing requirement	**1794**	**1858**	**2100**

9. The major component of the borrowing requirement is investment in fixed assets. Details of capital program costs and investment in fixed assets are discussed in paragraphs 1 through 7 above.

10. A second part of the borrowing requirement shown in table 6-2 is the funds for debt retirement, which are made up of maturing debt and premature retirement of outstanding debt. Hydro's borrowing program, discussed in chapter 7, administers maturing debt and premature retirement of outstanding debt.

11. Changes in other assets and liabilities in 1987, as shown in table 6-2, reflect higher inventories and accounts receivable, partly offset by higher accounts payable.

12. Funds from operations, namely net income, depreciation and other non-cash expenses included in the revenue requirement, lower the level of borrowing from what otherwise would be required, as shown in table 6-2.

Chapter 7
FIXED CHARGES - BORROWING PROGRAM; INTEREST & FOREIGN EXCHANGE

1. Hydro's borrowing program meets the borrowing requirement described in table 6-1 in chapter 6. Over time it is a major determinant of interest and foreign exchange expense which are shown in table 7-1.

Fixed charges - revenue requirement **Table 7-1**

$ millions

	1985	1986	1987
Fuel and fuel-related	1143	1069	1090
OM&A	966	1036	1120
Fixed Charges:			
Interest	**1325**	**1598**	**1837**
Foreign exchange	**176**	**178**	**130**
Interest & foreign exchange	**1501**	**1775**	**1966**
Depreciation	655	696	762
Net income	360	301	294
Secondary power and energy	(351)	(349)	(360)
Revenue requirement	4274	4529	4873
	====	====	====

BORROWING PROGRAM

2. Hydro's borrowing program in 1986 and 1987 is expected to be mainly from the Canadian market, as shown in table 7-2. The remainder is expected to be met from foreign bond markets with the foreign currency liabilities converted back to Canadian dollars using currency swaps. A major proportion is expected to be of intermediate term (five to ten years), with the remainder expected to be long term (over ten years).

3. Additional details on Hydro's borrowing program can be found in exhibit 7.1.4, 1986 Debt Management Strategy and exhibit 7.1.5, Capital Availability, 1986 - 2005.

Borrowing Program **Table 7-2**

$ millions

	1985	1986	1987
Market			
Canadian	1794	1458	1550
Foreign (swapped into Cdn $ liabilities)	0	400	550
Total Borrowing	1794	1858	2100
	====	====	====

FOREIGN EXCHANGE HEDGING STRATEGY

4. The 1986 Foreign Exchange Hedging Strategy and Program (exhibit 7.1.3) sets a long-term hedging target range, selects a long-term target within the range for use in 1986, and develops a plan for managing foreign exchange and exposure for the 1987-2013 period, and for managing foreign exchange requirements for 1986. The cost associated with this program is forecast to be about $9 million in 1987.

DEBT MANAGEMENT STRATEGY

5. The Debt Management Strategy (exhibit 7.1.4) consists of the Corporate Financing, Debt Restructuring and Debt Retirement Programs. The current Corporate Financing Program reflects in Canadian dollars the financing planned, including currency swaps, to meet the borrowing requirements. The Debt Restructuring Program is aimed at restructuring the existing fixed term debt using interest rate swaps to introduce floating rate debt. The Debt Retirement Program is currently focussing on restructuring the Debt Retirement Fund inventory such that future requirements for funds can be reduced while enhancing program effectiveness.

Interest - calculation for revenue requirement Table 7-3

$ millions

	1985	1986	1987
Bonds and long-term notes	2491	2621	**2698**
Other long-term debt*	16	14	**13**
Provisions	28	36	**49**
Short-term notes	16	24	**27**
Gross interest	2551	2696	**2787**
Less			
Capitalized in capital program	1049	926	**778**
Interest associated with fuel supplies	117	121	**116**
Earned on investments and other**	60	52	**56**
	1226	1099	**950**
Interest	1325	1598	**1837**

* Includes heavy water plant purchase agreement, head office lease agreement, and other capital leases
** Includes interest accrued to nuclear payback receivables

INTEREST AND FOREIGN EXCHANGE

6. Interest represents primarily the total cost of borrowing, less interest capitalized and other adjustments which are designed to effect a proper allocation of costs to current customers. Foreign exchange represents primarily the recognition of gains or losses, as defined by accounting policies, on the principal amount of debt denominated in a foreign currency. For 1987, the interest and foreign exchange component of the revenue requirement is $1966 million, as shown in table 7-1.

INTEREST

7. The determination of interest is shown in table 7-3. An analysis of the year-to-year changes in interest is shown in table 7-4.

8. As shown in table 7-4, facilities in service is the major factor affecting interest charged to current operations. Both new and existing facilities affect interest. When new facilities are placed in service, the associated interest is no longer capitalized, but is charged to current operations. The 1987 increase of $384 million is due to facilities placed in service and the return to operation of Pickering Units 1 and 2. Bruce Unit 8 will be placed in service during 1987, and there will be a full-year impact of Pickering Unit 8 and Bruce Unit 7 which are being placed in-service in 1986.

9. A reduction in the debt related to in-service facilities results from internally generated funds provided from depreciation and net income. This reduction decreases interest charged to current operations in 1987 by $123 million.

10. Changes in foreign exchange rates affect interest payments made in foreign currencies. The effect is slightly moderated by associated changes in interest capitalized. The value of the Canadian dollar, after deteriorating in 1986, is forecast to improve slightly in 1987. This improvement is the primary factor causing the $17 million decrease in interest in 1987 due to foreign exchange rates.

11. Other changes, as shown in table 7-4, result partly from changes in accounts payable, accrued interest, accounts receivable, inventories, and other assets and liabilities. These changes affect debt levels and therefore interest expense. The net impact of slight year-to-year changes in interest rates, affecting gross interest and interest capitalized, is also included in this category. Also included is the effect of funds provided from the amortization of unrealized foreign exchange losses. While this lowers borrowing, and hence interest expense, there is an offsetting interest improvement charge to foreign exchange expense, so that the revenue requirement is essentially unaffected.

Interest – changes **Table 7-4**

$ millions change from previous year

	1986	1987
Facilities placed in service	412	**384**
Reduced debt on in-service assets	(120)	**(123)**
Foreign exchange rates	10	**(17)**
Other	(29)	**(4)**
Total	273	**239**

FOREIGN EXCHANGE

12. Foreign exchange gains or losses are incurred primarily as a result of changes in the value of borrowing denominated in a foreign currency, due to a difference in the exchange rate between the time of borrowing and repayment. The major portion of foreign exchange costs is based on the net unrealized exchange loss arising from the translation of all foreign long-term debt at rates of exchange in the current period. This unrealized loss is amortized over the remaining life of the debt on an annuity basis to determine the foreign exchange costs charged to current operations.

13. The revenue requirement for foreign exchange is forecast to be $130 million in 1987 as shown in table 7-5. The decrease in 1987 reflects primarily the completion of amortization of foreign exchange losses on US dollar debt maturing in 1986 and 1987, and the slight anticipated strengthening of the Canadian dollar in 1987. Other foreign exchange transactions in 1985 and 1986 reflect primarily gains from short-term forward exchange contracts.

Foreign exchange costs **Table 7-5**

$ millions

	1985	1986	1987
US $	96	85	**76**
Eurodollar	75	70	**40**
Other currencies	19	33	**14**
Foreign exchange transactions – other	(14)	(11)	**–**
Foreign exchange	176	178	**130**

Chapter 8
FIXED CHARGES - DEPRECIATION

1. Depreciation expense, as shown in table 8-1, represents the recovery of the service costs associated with fixed assets in service and amortization of deferred costs. The revenue requirement for depreciation is forecast to be $762 million in 1987. Details of depreciation expense are shown in table 8-2.

Fixed charges - revenue requirement Table 8-1

$ millions

	1985	1986	1987
Fuel and fuel-related	1143	1069	1090
OM&A	966	1036	1120
Fixed charges:			
Interest	1325	1598	1837
Foreign exchange	176	178	130
Interest & foreign exchange	1501	1775	1966
Depreciation	**655**	**696**	**762**
Net income	360	301	294
Secondary power & energy	(351)	(349)	(360)
Revenue requirement	4274	4529	4873

2. Ontario Hydro's depreciation policy is to allocate the service costs of fixed assets to current operations in relation to the contributions made by these assets to the provision of service to customers. Service costs represent original cost plus all other significant capital costs less recoveries related to the asset. When the net costs of removal, upon the retirement of fixed assets, can be reasonably estimated and are significant, the amounts are amortized to the cost of operations on an annuity basis over the remaining service life of the fixed assets. Other net removal costs are charged to the cost of operations as incurred, as adjustments to depreciation expense.

Depreciation Table 8-2

$ millions

	1985	1986	1987
Fixed assets in service			
Generation			
Nuclear	208	268	**335**
Fossil	133	107	**117**
Hydraulic	30	29	**29**
Transmission/ distribution	75	79	**84**
Rural distribution	38	42	**46**
Administration/service	26	28	**32**
	510	553	**642**
Fixed asset removal provisions			
Fuel channel removal	91	83	**60**
Decommissioning nuclear stations	12	19	**17**
Amortization of deferred costs	39	39	**39**
Other	3	2	**3**
Total depreciation	655	696	**762**

3. The capital costs of fixed assets in service are depreciated on a straight line basis. Depreciation rates for the various classes of assets are based on their estimated service lives, which are subject to periodic review. Changes in depreciation resulting from changes in estimated service lives are implemented on a remaining service life basis from the year the change can be first reflected in electricity rates. Major components of generating stations are depreciated over the lesser of the service life expectancy of the component and the remaining service life of the associated generating station. Fixed assets removed from operation and mothballed for future use are amortized so that any estimated loss in value is charged to operations on a straight line basis over their expected non-operating period.

4. The estimated service lives of assets in the major classes in 1987, which reflect the 1986 recommendations of the Depreciation Review Committee, are as follows:

. Generating stations	
Nuclear	40 years
Fossil	30-35 years
Hydraulic	65-100 years
. Heavy water	until the year 2040
. Heavy water production facilities	20 years
. Transmission/distribution/ rural distribution	20-60 years
. Administration/service	5-60 years

5. Depreciation Review Committee's main 1986 recommendations are

- deferring a service life extension to 40 years for fossil generating stations from a range of 30-35 years pending the results of the Demand/Supply Options Study;

- increasing the annual amortization rates for Lennox and Thunder Bay Unit 1 to 5.0% from 3.3% of the capital cost of the units; and

- reducing annual fuel channel removal cost provisions from $83 million to $60 million.

6. A service life extension to 40 years for fossil generating stations was recommended in 1985 to be effective in 1986 by the Depreciation Review Committee. However, implementation of the service life extension was deferred for the purposes of rate setting and accounting because of last year's Ontario Energy Board recommendation. The DRC has reconsidered the key determinants for the service life of fossil generating stations and has concluded there is significant support for a service life extension. However, because of the OEB recommendation, implementation of the service life extension to 40 years for fossil generating stations is being deferred until the service life change can be considered in view of the results of the Demand/Supply Options Study.

7. The amortization rates for Lennox and Thunder Bay have been increased to 5% to recover the estimated unamortized loss in value of these generating units during their remaining non-operating periods. The increased annual amortization rate results from the use of a 30 year service life for fossil generating stations as a basis for estimating the annual rate of obsolescence rather than a 40 year service life as used for the 1986 Rate Proposal. The amortization rate also reflects current estimates of the probability of the stations' future use and non-operating periods which have not changed since last year.

8. For the years 1986 and 1987, depreciation includes provisions for the costs of removing fuel channels during the life of all in-service nuclear generating units and provisions for the cost of decommissioning these units after the end of their service lives. The replacement of fuel channels at Pickering Units 1 and 2 is scheduled to be completed by 1987. It is assumed that fuel channels at the remaining nuclear units will be replaced between the years 2000 and 2019. The estimated future costs for decommissioning nuclear facilities and for removing the fuel channels are being amortized to operations on an annuity basis over the remaining service life of the fixed assets. Changes in provision amounts are due to revisions to the cost estimates for the replacement of fuel channels at Pickering Units 1 and 2, the effect of updated estimates of interest and escalation rates, and the placing in service of new generating units.

9. The costs associated with the deferred Bruce Heavy Water Plant D and the cancelled Wesleyville project are amortized at a rate of 10% per year over the period 1984 to 1993. The annual amortization amount is shown in "Amortization of Deferred Costs" in table 8-2.

10. Table 8-3 provides an analysis of the change in depreciation expense. The major reasons for the increase of $66 million in depreciation in 1987 are

- additions to facilities in service, with Bruce Unit 8 being placed in service in 1987, and with Pickering Unit 8 and Bruce Unit 7 being in service for a full year in 1987 for the first time ($80 million increase); and

- revised amortization rates for Lennox and Thunder Bay Unit 1 ($9 million increase);

partly offset by

- a lower fuel channel removal cost provision for Pickering Units 1 and 2 primarily from a reduced estimate of retubing expenditures ($23 million decrease).

Depreciation – changes **Table 8-3**

$ millions change from previous year

	1986	1987
Fixed assets placed in service		
Generation	80	67
Other	11	13
	90	80
Revisions to amortization rates	–	9
Fully depreciated generation stations	(47)	
Revisions to provisions for		
Nuclear decommissioning	7	(2)
Fuel channel removal	(9)	(23)
Other	(1)	2
Total	40	66

Chapter 9
FINANCIAL MATTERS

A. NET INCOME

1. Hydro's net income requirement is set out in table 9A1.

Net income - revenue requirement **Table 9A1**

$ millions

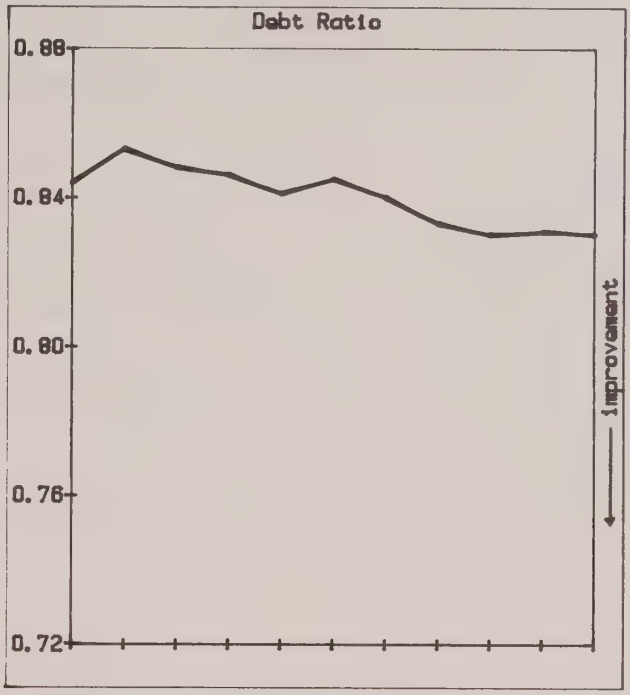
	1985	1986	1987
Fuel and fuel-related	1143	1069	1090
OM&A	966	1036	1120
Fixed charges	2156	2471	2728
Net income	**360**	**301**	**294**
Secondary power and energy	[351]	[349]	[360]
Revenue requirement	4274	4529	4873
	====	====	====

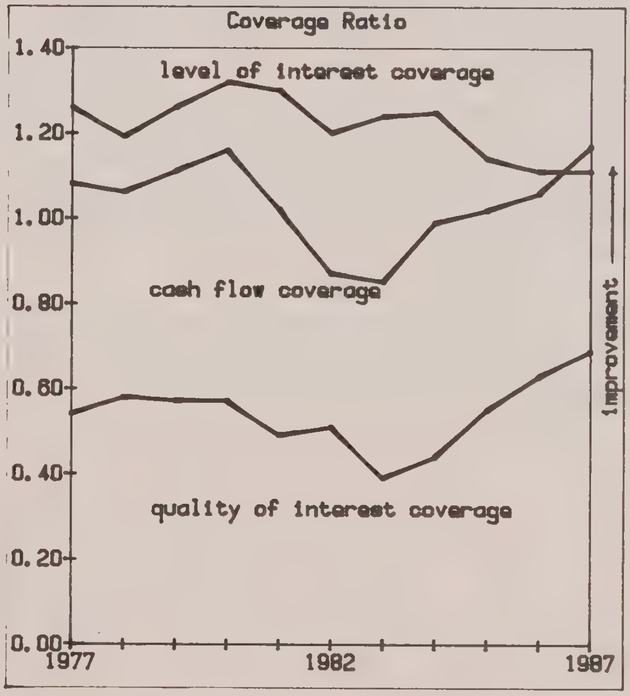
2. Hydro's policy is to develop net income requirements by examining the size and pattern of rate increases, the availability of capital, and financial soundness.

3. Financial soundness is assessed using the level and quality of interest coverage, the debt ratio, and the cash flow coverage ratio. The level of interest coverage and the debt ratio have been used to assess financial soundness since the mid-1970s. In 1983, Hydro completed a review of its net income policy which also identified the quality of interest coverage and the cash flow coverage ratio as further relevant indicators of financial soundness.

4. The level and quality of interest coverage indicate Hydro's ability to cover its interest payments. Increases in these ratios indicate a strengthening of financial soundness.

Financial indicators - 1976 to 1986 **Chart 9A2**





Net income, rate increase, and financial indicators - 1977 to 1987 Table 9A3

$ millions

	Actual									Forecast	
	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
Net income											
$ millions*	194	168	268	376	407	348	472	575	360	301	294
% of target**								89	60	55	60
Rate increase***	30.3	9.5	9.8	8.3	9.4	9.6	8.4	7.8	8.6	4.0	4.9
Financial indicators											
Debt ratio	0.844	0.853	0.848	0.846	0.841	0.845	0.840	0.833	0.830	0.831	0.830
Interest coverage ratios											
Level	1.26	1.19	1.26	1.32	1.30	1.20	1.24	1.25	1.14	1.11	1.11
Quality	0.54	0.58	0.57	0.57	0.49	0.51	0.39	0.44	0.55	0.63	0.69
Cash flow coverage ratio	1.08	1.06	1.11	1.16	1.02	0.87	0.85	0.99	1.02	1.06	1.17

* Income before extraordinary items in 1976, 1978 and 1980
** Applicable for 1984 onwards
*** Bulk power 1976-1982; all customers thereafter

5. The debt ratio indicates the relative size of Hydro's debt with respect to its assets. A reduction in the debt ratio indicates improvement in financial soundness.

6. The cash flow coverage ratio measures the extent to which funds from operations cover interest payments. A cash flow coverage of less than one indicates an undesirable situation where some borrowing is required to pay interest.

7. Hydro's net income target is based on providing a coverage of 1.05 on interest charged to operations and a coverage of 1.50 on interest capitalized; and a cash flow coverage ratio of at least 1.0. Consequently, target net income and the associated level of interest coverage will vary each year, depending on the amount of interest charged to operations and the amount capitalized.

8. In assessing the size and pattern of rate increases, consideration is given to the level of the rate increase in real terms, and the rate objective of having no real increase in the price of electricity over the 1980s. Trends in rate increases, net income and financial soundness indicators are shown in table 9A3.

9. Since capital availability was not a constraint in 1985 and 1986, net income requirements and rate increases were based on consideration of the level of rates and financial soundness. Capital availability in 1987 is also not expected to influence rate decisions.

10. In planning 1986 rates, there was a relatively favourable cost outlook. In addition, the expectation of lower inflation in 1985 had the effect of increasing rates in real terms. In balancing rate and financial soundness objectives in 1986, the emphasis was on a rate increase below the rate of inflation to move rate levels lower in real terms, with movement towards target financial soundness in future years.

11. The current cost and rate outlook for 1987 is less favourable than a year ago. However, some improvement is expected later in the decade. In an April 1986 letter, the Treasurer of Ontario advised Hydro that, with some easing of rate pressures expected later in the decade, he would expect Hydro to take reasonable steps toward smooth rate increases over the next few years.

12. In this context, a 1987 rate increase of 4.9% is judged to provide an acceptable balance between rate and financial soundness objectives. The increase is low in real terms, thus constraining the growth of real rate levels. It also provides a basis for improving financial soundness in future years. Under the current outlook for 1988 and 1989, both rate and financial soundness objectives, can be achieved by 1989, with rate increases below the forecast rate of inflation in each year.

Chapter 9
FINANCIAL MATTERS

B. FINANCIAL POLICY

Accounting Policies

1. Changes in matters of accounting policy, including procedures and practices, have been summarized in this section. This summary permits changes which affect costs or revenues in the period under review, or which could affect later periods, to be discussed in one place. The items submitted represent new or revised approaches from those used in the proposal on 1986 rates.

2. Hydro's accounting policies change in response to changes in generally accepted accounting principles (GAAP), new circumstances requiring specialized accounting, or reassessments of alternatives acceptable under GAAP that are appropriate in Hydro's rate-setting environment. The reviews undertaken and changes incorporated in the 1987 rate proposal reflect reassessments of acceptable alternatives, except for the Policy on Accounting for Pension Costs and Obligations, which is in response to changes in GAAP.

3. In reviewing accounting policies, the following matters are considered in arriving at the positions submitted

- intergenerational fairness to customers;
- practices and trends in other utilities;
- GAAP in Canada and in other countries, primarily the US;
- history of the accounting issue in Hydro;
- consistency with other Hydro policies;
- identification and consideration of relevant and practical alternatives;
- concurrence of external auditors; and
- financial impact.

Accounting for Translation of Foreign Currency

4. The accounting policy for the Translation of Foreign Currency has been amended in the following areas:

(a) Foreign Exchange Gains/Losses on Premature Debt Retirement

The amortization period for foreign exchange gains and losses on debt retired prematurely has been changed. This change is consistent with recommendations of the OEB in previous reports. It affects gains and losses on early redemption of foreign debt which is replaced with new debt in the same currency, continuing the exposure to foreign currency risk. Under present policy, implemented in 1984, such gains and losses are amortized over the life of the replacement debt. Beginning in 1986, they will be amortized over the remaining term of the redeemed debt. Exhibit 9.1.4 provides further details on this matter. This change will reduce operating costs for 1986 by an estimated $0.4 million and has an equal effect on the 1987 revenue requirement.

(b) Accounting for Foreign Currency Hedging

Hydro has reviewed the accounting policy implications of the Foreign Exchange Management Policy. As a result of this review, the Accounting Policy for the Translation of Foreign Currency has been expanded to deal with Hydro's increased foreign currency hedging activities. The amended policy specifies the accounting criteria that must be met for a transaction to qualify as a hedge. It also differentiates between hedges of anticipated transactions and those of existing assets or liabilities and provides the appropriate accounting for each. Exhibit 9.1.6 provides further details on this matter.

Accounting for Uranium Fuel Supply in a Downsizing Environment

5. Hydro's long-term contracts for uranium concentrate exceed currently foreseen requirements. The adequacy of Hydro's accounting for uranium concentrate in the circumstances of reducing fuel supply commitments has been examined in a report filed as exhibit 9.1.7. As a result of the findings of that examination

- it was found that the value of advances to uranium suppliers is sustained as long as the associated contracts have net economic value to Ontario Hydro;
- starting in 1985, the basis for amortizing capitalized interest on advances to uranium suppliers has been changed from contracted to estimated required quantities; and
- all other aspects of the present accounting treatment for uranium concentrate are appropriate in a downsizing environment.

This accounting provides the most appropriate allocation of uranium concentrate costs to current and future customers. It will result in an increase in the 1987 revenue requirement of $4 million.

Policy on Accounting for Pension Costs and Obligations

6. In April of 1986, the Canadian Institute of Chartered Accountants (CICA) released new recommendations on accounting for pension costs which differ in certain areas from Hydro's present pension accounting.

7. Under the new accounting policy, the pension costs ultimately included in rates each year are likely to differ from the cash contributions. The difference is recorded as a deferred charge or pension accrual. At present there is no such difference. The new policy differs in terms of the economic assumptions used, the basis for valuing pension plan assets, the method of amortizing pension plan surplus or deficit, and the amortization period.

8. Beginning in 1987, Hydro's pension costs will be accounted for in accordance with the new CICA recommendations. The new accounting policy and a supporting report will be filed as exhibit 9.1.5 as soon as it becomes available.

C. FINANCIAL STATEMENTS

1. The three financial statements included in this section contain actual results for 1985, the current outlook for 1986 and the forecast for 1987. A minor format change has been made to the Statement of Financial Position since the proposal on 1986 rates. The Statement of Funds Used for Investment in Fixed Assets has been replaced by the Statement of Source of Cash Used for Investment in Fixed Assets.

2. In table 9C2, the Statement of Financial position, "Long-term accounts payable and accrued charges" are now shown separately under "Other Liabilities." In previous years, this item was included as a current liability under "Accounts payable and accrued charges."

4. The Statement of Funds Used for Investment in Fixed Assets has been changed in name and format to the Statement of Source of Cash Used for Investment in Fixed Assets, table 9C3. The revised statement reflects CICA recommendations to identify cash transactions more clearly.

Statement of operations for the years ending December 31 Table 9C1

$ millions

	1985	1986	1987
Revenues			
Primary power and energy			
Municipal utilities	2891	3051	3258
Rural retail customers	815	859	933
Direct industrial customers	568	619	682
	4274	4529	4873
Secondary power and energy	351	349	360
	4625	4878	5233
Costs			
Operation, maintenance and administration	966	1036	1120
Fuel used for electric generation	968	919	890
Water rentals	87	91	94
Power purchased	163	121	72
Nuclear agreement – payback	(75)	(62)	34
Depreciation	655	696	762
	2764	2801	2973
Income before financing charges	1861	2076	2261
Interest	1325	1598	1837
Foreign exchange	176	178	130
	1501	1775	1966
Net income	360	301	294
Appropriation for:			
Deb retirement	252	291	328
Stabilization of rates and contingencies	108	10	(33)
	360	301	294

Statement of financial position as at December 31 Table 9C2

$ millions

	1985	1986	1987
Assets			
Fixed assets			
Fixed assets in service	20 604	23 594	26 402
Less: accumulated depreciation	4 614	5 183	5 841
	15 990	18 411	20 561
Construction in progress	8 159	7 716	7 065
	24 149	26 127	27 626
Current assets			
Cash and short-term investments	18	0	0
Accounts receivable	550	567	605
Fuel for electric generation	1 015	1 034	1 093
Materials and supplies, at cost	215	246	262
	1 798	1 847	1 959
Other assets			
Unamortized debt costs	1 897	1 679	1 410
Unamortized advances for fuel supplies	899	890	886
Unamortized deferred costs	313	273	234
Long-term accounts receivable and other assets	264	384	391
	3 373	3 226	2 922
	29 320	31 200	32 507
Liabilities			
Long-term debt			
Bonds and notes payable	22 728	23 968	24 805
Other long-term debt	197	174	154
	22 925	24 142	24 959
Less payable within one year	407	1 060	1 191
	22 518	23 082	23 768
Current liabilities			
Accounts payable and accrued charges	549	615	689
Short-term notes payable	223	336	309
Accrued interest	710	758	755
Long-term debt payable within one year	407	1 060	1 191
	1 889	2 769	2 944
Other liabilities			
Long-term accounts payable and accrued charges	158	166	175
Accrued irradiated fuel disposal & fixed asset removal costs	311	438	581
	469	604	756
Equity			
Equities accumulated through debt retirement appropriations	2 618	2 909	3 237
Reserve for stabilization of rates and contingencies	1 699	1 709	1 675
Contributions from the Province of Ontario as assistance for rural construction	127	127	127
	4 444	4 745	5 039
	29 320	31 200	32 507

Statement of source of cash used for investment in fixed assets for the years ending December 31 **Table 9C3**

$ millions	1985	1986	1987
Operating activities			
Cash provided from operations	1055	1151	1242
Financing activities			
Long-term debt issued	1781	1839	2079
Less retirements	1024	602	1138
Cash provided from financing	757	1238	941
Investing activities in other assets			
Decrease (increase)	18	(36)	(53)
Cash from operating, financing and other investing activities	1830	2353	2130
Changes in cash and cash equivalents			
Decrease (increase)	814	131	(27)
Cash used for investment in other fixed assets	2644	2484	2103
Changes in accounts payable and accrued charges affecting investment in fixed assets			
(Decrease) increase	(103)	59	47
Investment in fixed assets	2541	2542	2149

Statement of financial position as at December 31 Table 9C2

$ millions

	1985	1986	1987
Assets			
Fixed assets			
Fixed assets in service	20 604	23 594	26 402
Less: accumulated depreciation	4 614	5 183	5 841
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(Decrease) increase	(103)	59	47
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Chapter 10
PROPOSED RATES

A. OVERVIEW

1. Consistent with the approach adopted in 1985, Hydro is deferring any further rate structure reform for the next two years.

2. In its review of the proposed 1986 rates, the OEB discussed the deferral and encouraged all interested parties to participate in the discussion of the proposed rate structure reform.

3. Meetings are being held between Hydro and the two major customer representative associations, the MEA (previously OMEA and AMEU) and AMPCO, and other interested parties. The purpose of the consultation process is to develop as much consensus as possible on future rate structure reform.

4. The proposed 1987 electricity rates are based on the rate structure approved for 1986, which includes experimental special condition classifications. The only changes for 1987 rates are the following refinements to the underlying cost allocation process

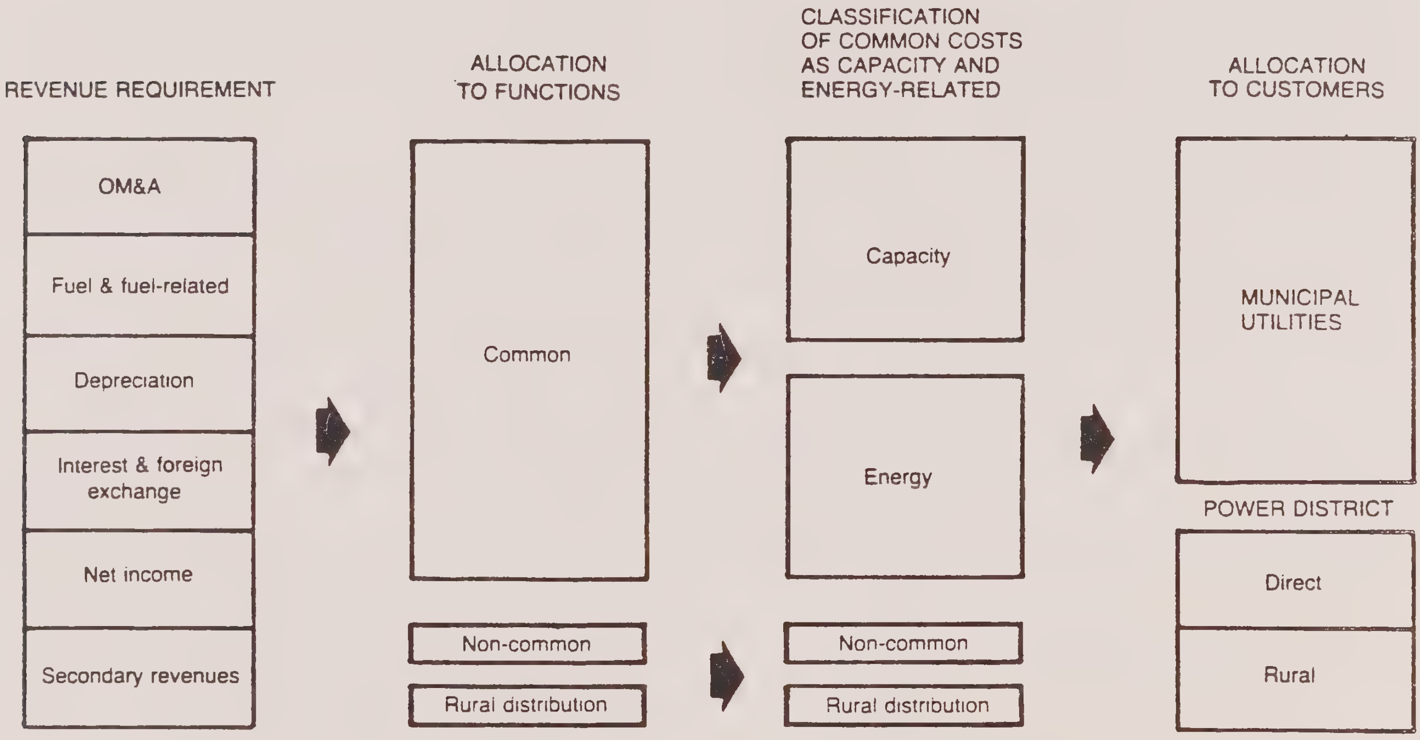
- the transfer of customer administration costs from common to non-common;
- a more consistent allocation of actual year-end net income appropriations; and
- the recognition of scheduled-hour power sales in the allocation.

5. The experimental special condition classifications are outlined in section C of this chapter. They are the same as proposed for 1986 except

- the Industrial Dual Energy Rate proposed last year for dual-fuelled boilers has been dropped;
- monthly power has been expanded to include an off-peak rate; and
- the availability of intermittent power has been extended to include a limited number of hours of coal-based operation.

6. As part of the process of establishing electricity rates, costs included in the total annual revenue requirement are first allocated to cost categories referred to as functions: the common function, non-common functions, and the rural distribution function. The common function costs are then split into capacity and energy-related components. Subsequently, costs are allocated on the basis of usage to distributors (individual municipal utilities and the power district) and to the direct and rural customer classes within the power district. The cost allocation process is illustrated in chart 10A1 and explained in greater detail in section B of this chapter.

Cost allocation process **Chart 10A1**



Chapter 10
PROPOSED RATES

B. COST ALLOCATION PROCESS

Allocation of Costs to Functions

1. As described in section 10A, costs which are included in the total annual revenue requirement, are allocated to three categories of functions: common, non-common and rural distribution. With the exception of the three refinements proposed for 1987, this allocation process is the same as for both 1985 and 1986 rates.

2. The common function generally consists of the costs of the facilities and activities that are incurred to ensure the same level of service for all customers. Non-common functions generally consist of the costs of facilities and activities associated with particular service conditions which are not provided to all customers by Hydro. The costs in the rural distribution function apply only to the retail distribution of electricity to the rural customer class.

3. The 1987 functional costs appear in table 10B1. As shown there, the costs to be allocated differ from the total annual revenue requirement by the amount of revenues from sales of special condition classifications. Adjusting the total revenue requirement for these revenues and excluding the peak loads and energies (as shown in tables 10B2 and 10B3) ensures that the net benefit from sales of special condition classifications is reflected in standard rates.

4. Costs within the common function are accumulated in three components. The costs associated with producing electricity are accumulated in the generation component. The costs of providing a high voltage network of transmission and transformation facilities and of those low voltage lines required to deliver electricity to distributors' boundaries are accumulated in the grid component. All other common costs are accumulated in the general component including such items as net revenues from secondary sales, costs of deferred assets, the cost of rural residential rate assistance, and revenues from sales to distributors under special condition classifications.

Allocation of costs to functions - 1987 **Table 10B1**

$ millions	
Common function	
Generation	3757
Grid	361
General	307
Total common function	4425
Non-common functions	
Transformation	114
Municipal distributors DS	1
Power district DS	24
Distribution lines	22
Customer administration	
- municipal	48
- direct	8
- rural	21
Sundry	(17)
Total non-common functions	221
Rural distribution function	221
Total costs to be allocated*	4867

* Total revenue requirement reduced by revenue from special condition classifications ($6 million)

5. The transformation function generally consists of the costs of transformation stations crossing the 50 kV voltage level. More specifically, this function includes the costs of transformer stations that step power down from above to below 50 kV and also a proportional share of the costs of distributing stations that step power down from above to below 50 kV. Since these distributing stations generally supply power at lower voltage levels than transformer stations, they are viewed as performing two transformation steps - stepping power down from above to below 50 kV and from below 50 kV to lower voltages. The associated station costs are split accordingly between the transformation and power district distribution stations functions. The latter allocation reflects the fact that almost all these stations are used by the power district.

6. The municipal distributors distribution stations function consists of the costs of stations that transform power from below 50 kV to lower voltages and that exclusively serve a single municipal distributor.

7. The power district distribution stations function consists of the costs of all remaining stations that transform power from below 50 kV to lower voltages. This includes the costs of stations that exclusively serve the power district, as well as stations that are shared by the power district and one or more municipal distributors. This function also includes the remaining portion of the costs of distribution stations that transform power from above to below 50 kV (see paragraph 5). While the majority of the functional costs remain with the power district, a portion is subsequently transferred to municipal distributors that use the facilities in this function (see paragraph 23).

8. The distribution lines function consists of the costs associated with low voltage bulk system lines (below 50 kV) lying within a distributor's boundary and serving only that distributor - a municipal utility or the power district. The remaining low voltage bulk system line costs are considered to be common to all customers.

9. The customer administration functions generally consist of the costs of customer service activities associated with the provision of bulk power and interest costs associated with customer account receivables. Since customer administration costs are identified by customer category, Hydro proposes to establish three separate functions, one for each customer category.

10. The sundry function serves as a means of redistributing costs among customer categories in order to recognize special contract adjustments and discounts for supply conditions such as interruptible or 230 kV supply. It will now also include the adjustment for scheduled hour power sales and the power district share of net revenues from sales under special condition classifications.

11. The rural distribution function consists of the costs that apply only to the rural customer class net of rural residential rate assistance of $87 million. The cost of this assistance, as calculated in exhibit 10.1.4, is included in the common general costs to be shared by all customers.

12. A refinement has been made to the allocation of actual year-end net income appropriations. This affects the determination of equity balances used in the allocation of net income and interest expense to functions. Beginning with the 1986 year-end, the net income appropriation determined by matching costs and revenues for the rural distribution function is absorbed in the accumulated equity balance associated with that function. Previously a portion of this amount was reflected in the rural class surplus/deficit balance. This refinement results in a consistent treatment for all functions.

13. Common and non-common costs are initially allocated to the municipal utilities and the power district. Within the power district, common and non-common costs are then further allocated to the direct and rural customer classes. Rural distribution functional costs are allocated directly to the rural customer class.

Allocation of Common Costs to Customers

14. The allocation of common costs is generally the same as for 1985 and 1986 rates. It continues to be a two-step process in which costs are classified as capacity-related or energy-related, and then allocated to customers based on their peak power and energy usage.

15. Consistent with the intent to maintain the common cost capacity:energy split at the 1985 level of 50:50, customer administration costs continue to be treated as capacity-related for classification purposes. This ensures that the transfer of customer administration costs to non-common has no impact on the proportion of costs allocated to customers on the basis of energy usage.

16. Energy-related common costs are allocated to distributors, and within the power district to the direct and rural customer classes, based on their respective energy usage. Customer delivered forecast energy is shown in table 10B2.

Customer delivered energy – 1987 **Table 10B2**

GWh	
Municipal utilities	79 944
Power district	
Direct customers	19 483
Rural customers	16 095
Total customer delivered energy*	115 522

* Excludes special condition classifications

17. Capacity-related common costs are allocated to distributors and, within the power district, to the direct and rural customer classes, in proportion to their average monthly 60-minute peak loads. Forecast peak loads for distributors and customer classes within the power district are shown in tables 10B3 and 10B4, respectively.

Distributor peak loads – 1987 **Table 10B3**

Average monthly peaks

	Peak loads (MW)
Municipal utilities	12 570
Power district	4 955*

* Excludes special condition classifications

Power district customer class peak loads – 1987 **Table 10B4**

Average monthly peaks

	Peak loads (MW)
Direct customers	2470*
Rural customers	2599

* Excludes special condition classifications

Allocation of common costs – 1987 **Table 10B5**

	Municipal utilities		Power district		Total
	Total ($M)	Unit cost	Total ($M)	Unit cost	($M)
Capacity costs	1559	10.34($/kW/mth)	614	10.34($/kW/mth)	2173
Energy costs	1558	1.95(¢/kWh)	694	1.95(¢/kWh)	2252
Total	3117		1308		4425

18. The distributor peak load for municipal utilities is their forecast peak power, as shown in chapter 2, table 2-11. The distributor peak load for the power district is derived from the customer-delivered peak power for direct and rural customers to which a coincidence factor has been applied. The direct and rural customer class peak loads are derived by applying class-specific coincidence factors to customer-delivered peak power for direct and rural customers.

19. The allocation of common costs to distributors and customer classes within the power district is shown in tables 10B5 and 10B6 respectively.

Allocation of power district common costs – 1987 **Table 10B6**

$ millions

	Power district	Direct customers	Rural customers
Capacity costs	614	299	315
Energy costs	694	380	314
Total	1308	679	629

Allocation of Non-common Costs to Customers

20. The allocation of non-common costs to customers is the same as for 1985 and 1986 rates with the exception that it now includes customer administration costs. For each of the non-common functions, including the three new customer administration functions, costs of facilities and activities are allocated only to those customers who benefit from the facilities and activities. Although the majority of non-common costs are pooled and charged out at uniform rates, the costs of certain non-common facilities are assigned directly to individual distributors. The allocated non-common costs for 1987 appear in tables 10B7 and 10B8.

21. Costs in the transformation function are pooled and allocated to distributors and customer classes within the power district on the basis of their peak loads associated with these facilities.

22. Costs in the municipal distributors distribution stations function are accumulated and specifically charged to municipal distributors on an individual facility basis.

Allocation of non-common costs - 1987 Table 1087

$ millions	Municipal utilities	Power district	Total
Transformation	91	23	114
Municipal distributors DS	1	0	1
Power district DS	2	22	24
Distribution lines	-	22	22
Customer administration			
Municipal	48	0	48
Direct	0	8	8
Rural	0	21	21
Sundry	(1)	(16)	(17)
Total	141	80	221
Unit costs			
Transformation ($/kW/month)	0.66	0.66	
Power district DS ($/kW/month)	0.86	0.86	
Distribution lines ($/kM/month)	354	354	
Customer administration ($/kW/month)	0.32	0.49	
Switchgear credit ($/kW/month)	(0.10)		

Allocation of power district non-common costs - 1987 Table 1088

$ millions	Power district	Direct customers	Rural customers
Transformation	23	4	19
Power district DS	22	0	22
Distribution lines	22	1	21
Customer administration			
Direct	8	8	0
Rural	21	0	21
Sundry	(16)	(16)	-
Total	80	(3)	83
	===	===	===

23. Costs in the power district distribution stations function are pooled and a unit cost per kW is determined on the basis of all peak loads associated with these facilities. The unit cost is used to transfer a share of functional costs to municipal distributors supplied from stations in this function. The remaining power district costs are allocated directly to the rural customer class since there are no direct customers supplied from these stations.

24. Costs in the distribution lines function are pooled and charged directly to each distributor on the basis of line length specific to that distributor. Within the power district, the costs of lines specific to either the rural or the direct customer class are assigned on the basis of each class's specific line length. The costs of lines shared by the two customer classes are assigned on the basis of relative peak power.

25. Costs in the municipal, direct and rural customer administration functions are allocated directly to the appropriate customer category. For the municipal utility category, customer administration costs are allocated to individual distributors based on their peak loads.

Chapter 10
PROPOSED RATES

C. RATES AND REVENUE

1. The allocation of the revenue requirement for the municipal utilities and the rural and direct customer classes of the power district is summarized in table 10C1. This allocation was described in section B of this chapter.

Allocation of total costs – 1987 **Table 10C1**

$ millions

	Common	Non-Common	Rural distribution	Total
Municipal utilities	3 117	141	0	3 258
Power district				
Direct customers	679	(3)*	0	676
Rural customers	629	83	221	933
Total	4 425	221	221	4 867

* Includes credit of $16 million from sundry function

2. In its reports on 1985 and 1986 rates, the OEB accepted the principle of using incremental cost-based rates to market energy generated by surplus capacity.

3. For 1986 electricity rates, Hydro implemented range rates, both in a general form and for the following specific applications

- intermittent power;
- monthly power; and
- Bruce Energy Centre.

The proposed Industrial Dual Energy Rate was not implemented in 1986.

4. The terms and conditions for these classes of power are unchanged for 1987, with two exceptions

- for intermittent power, the availability has been increased to 1500 hours and includes a limited number of hours of coal-based generation; and
- for monthly power, the terms and conditions have been refined so that cost-based rates are also available to customers requiring power only in the off-peak periods.

5. Hydro also proposes to continue offering the other incentive rates introduced for 1986 rates, namely

- an industry average rate; and
- short-term scheduled-hour power.

6. Further discussion of these special condition rates is included in exhibit 10.1.7.

MUNICIPAL UTILITIES

7. Wholesale rates applicable to municipal utilities are based on the unit costs as shown in table 10B5 and 10B7 of section B. Charges are made on a monthly uniform basis. As a result of rounding the energy rate to the nearest hundredth of a cent, the monthly demand rates have been decreased by $0.01/kW in order to recover the allocated revenue requirement.

8. The resulting schedule of wholesale rates, specific charges, and credits proposed for municipal utilities in 1987 is shown in table 10C2.

Rates to municipal utilities **Table 10C2**

	1986	1987
Main classifications		
Monthly demand rates ($/kW)		
230 kV	9.86	10.37
115 kV	10.13	10.64
Less than 115 kV	10.78	11.30
Energy rate (¢/kWh)	1.87	1.95
Other monthly charges and credits		
Ownership of low voltage switchgear credit ($/kW)	0.10	0.10
Specific facility charges		
Lines ($/km)	339	354
Distributing stations	*	*
Use of shared distributing stations ($/kw)	0.77	0.86
Special condition classifications	**	**

* As applicable to individual utilities

** Intermittent power, monthly power, short-term scheduled-hour power and industry average may be sold to customers of municipal utilities under tri-party agreements

9. Ontario Hydro supplies power to two companies which in turn distribute power, Gananoque Light and Power Limited and Great Lakes Power Limited. The rates are based on the unit costs applicable to municipal utilities under corresponding conditions of supply.

10. Application of the proposed schedule of rates, charges, and credits is estimated to increase the overall revenue from municipal utilities by 4.6% over the amount that would have been obtained in 1987 at 1986 rates.

11. Similar to 1985 and 1986, it is proposed to continue to offer direct relief in 1987 to 20 utilities to limit their rate increase to a maximum of 1 percentage point above the customer category average rate increase. It is estimated that this relief will total less than $160,000.

12. The forecast distribution of bill impacts to individual utilities resulting from the proposed rates, after impact relief, is shown in table 10C3. Impacts range from a low of 4.5% to a high of 5.6%. The variation in percentage increase is due primarily to differences in utility load factors, delivery voltages, and charges for specific facilities.

Impacts on municipal utilities - 1987 **Table 10C3**

Percentage increase in individual bills	Number of utilities In interval	Number of utilities Cumulative
4.6 or less	188	188
4.7 to 5.0	108	296
5.1 to 5.6	20	316
Total	316	

DIRECT CUSTOMERS

13. Direct customers are retail customers of the power district with power demands exceeding 5 MW, and are served directly under contracts with Hydro. Direct customers located within a municipality are supplied by Hydro with the agreement of the municipality.

14. The categories of direct customer service for 1987 are as follows

- main classifications

  firm;
  capacity interruptible;
  scheduled-hour class 1;
  scheduled-hour class 2;

- special condition classifications

  intermittent;
  monthly;
  Bruce Energy Centre;
  short-term scheduled-hour power;
  industry average;

- auxiliary classifications

  excess;
  standby;
  supplemental;
  short-term.

15. Table 10C4 sets out the proposed rates for main and special condition classifications for 1987.

16. The rates for the auxiliary classifications have been established as in previous years. The rates for excess, supplemental, and short-term power are set at 125% of the firm power demand charge, while standby power rates are equal to the firm power demand charge. All energy associated with the auxiliary classifications is charged at the main classification energy rate.

Rates to direct customers Table 10C4

	1986	1987
Main classifications		
Monthly demand rates ($/kW)		
230 kV		
Firm	7.40	7.91
Interruptible	6.46	6.97
Scheduled-hour class 1	0.56	0.00
Scheduled-hour class 2	0.34	0.00
115 kV		
Firm	7.63	8.14
Interruptible	6.69	7.20
Scheduled-hour class 1	0.76	0.12
Scheduled-hour class 2	0.47	0.07
Less than 115 kV		
Firm	8.22	8.75
Interruptible	7.28	7.81
Scheduled-hour class 1	0.97	0.31
Scheduled-hour class 2	0.59	0.19
Energy rate (¢/kWh)	2.03	2.11
Special condition classifications		
Intermittent (¢/kWh)	1.00	1.30
Monthly	*	*
Bruce Energy Centre	**	**
Short-term scheduled-hour power	*	*
Industry average	***	***

* Set on a monthly basis
** Customer specific
*** Industry specific

17. Since there are no specific facility cost allocations to individual direct customers, all costs allocated to this class are recovered through a uniform rate structure, differentiated by service voltage and class of power. The 115 kV direct customer rate is generally determined from the common cost allocations to the class, as shown in table 10B6, after transferring a portion of capacity costs to the energy cost allocation. The unit demand charge thus determined becomes the basis for the 115 kV demand rate, and a unit energy rate is applied at all voltage levels for the main service classifications. Discounts from or surcharges to the 115 kV demand rate are separately determined and accounted for through the various non-common allocations of costs and sundry credits to the direct class.

18. As with the existing 1986 rates, the energy rates for direct customers proposed for 1987 are higher, and the demand rates lower, than those for municipal utilities. The demand rates are lower because of the effects of diversity within the direct class and between the direct and rural classes, and because some capacity costs are collected through the energy rate. This transfer between the demand and energy rates achieves a more equitable distribution of costs among customers with high and low load factors.

19. The application of these rate schedules is estimated to increase revenue from the direct customer class by 5.0% over the amount that would have been obtained in 1987 at 1986 rates.

20. The forecast distribution of bill impacts for individual direct customers is set out in table 10C5. Differences in bill impacts will depend primarily on the individual load factor, service voltage, and the mixture of firm and interruptible demand. Direct customer bill impacts are forecast to vary from 4.7% to 6.9%.

Impacts on direct customers – 1987 **Table 10C5**

Percentage increase in individual bills	Number of customers: In interval	Number of customers: Cumulative
5.0 or less	46	46
5.1 to 6.0	57	103
6.1 to 6.9	2	105
Total	105	

REVENUES

21. The estimated revenues from municipal utilities and direct customers for 1987 are set out in tables 10C6 and 10C7 respectively.

Forecast revenue from municipal utilities Table 10C6

	Billing quantities* 1987	Monthly rates 1986	Monthly rates 1987	Revenue ($M) for 1987 at: 1986 rates	Revenue ($M) for 1987 at: 1987 rates
Demand ($/kW)					
230 kV	2 050 MW	9.86	10.37	20	21
115 kV	5 774 MW	10.13	10.64	58	61
Less than 115 kV	143 012 MW	10.78	11.30	1 542	1 616
Energy (¢/kWh)	79 944 GWh	1.87	1.95	1 495	1 559
Other charges and credits					
Low voltage switchgear credit ($/kW)	31 395 MW	(.10)	(.10)	(3)	(3)
Specific facility charge					
Lines ($/km)	1 518 km	339	354	1	1
Distributing stations		**	**	0	1
Use of shared distributing station ($/kW)	2 499 MW	0.77	0.86	2	2
Total				**3 115**	**3 258**

* Distributing companies included in appropriate billing quantities

** As applicable to individual utilities

Forecast revenue from direct customers — **Table 10C7**

	Billing quantities* 1987	Monthly rates 1986	Monthly rates 1987	Revenue ($M) for 1987 at: 1986 rates	Revenue ($M) for 1987 at: 1987 rates
Demand ($/kW)					
230 kV					
Firm	8 215 MW	7.40	7.91	61	65
Interruptible	3 395 MW	6.46	6.97	22	24
Scheduled-hour power class 1	72 MW	0.56	0.00	0	0
Scheduled-hour power class 2	0 MW	0.34	0.00	0	0
115 kV					
Firm	11 671 MW	7.63	8.14	89	95
Interruptible	2 711 MW	6.69	7.20	18	19
Scheduled-hour power class 1	0 MW	0.76	0.12	0	0
Scheduled-hour power class 2	60 MW	0.47	0.07	0	0
Less than 115 kV					
Firm	4 919 MW	8.22	8.75	40	43
Interruptible	2 640 MW	7.28	7.81	19	21
Scheduled-hour power class 1	120 MW	0.97	0.31	0	0
Scheduled-hour power class 2	0 MW	0.59	0.19	0	0
Energy (¢/kWh)	19 397 657 MWh	2.03	2.11	394	409
Sub-Total (as per table 10C1)				643	676
Special condition classification sales**	260 681 MWh			6	6
Total				649	682

* Includes reductions for special contract adjustments
**For details, see exhibit 10.1.7

Ontario Hydro
700 University Avenue
Toronto, Ontario
M5G 1X6

Appendix 1

Tom Campbell, Chairman of the Board

DELIVERED BY HAND

April 14, 1986

The Honourable Vincent G. Kerrio
Minister of Energy and Natural Resources
Room 6323, Whitney Block
99 Wellesley Street West
TORONTO, Ontario
M7A 1W3

Dear Minister:

In accordance with section 37 of the Ontario Energy Board Act, Ontario Hydro hereby submits to you its proposal for changes in the electricity rates charged to its municipal utility and direct industrial customers, effective January 1, 1987. Details of the proposed rates are provided in the attached documents.

The proposed changes in the rates to be charged to municipal utilities correspond to an average increase of 4.6 per cent. The increase will vary among the 316 municipal utilities according to their individual monthly peak demands, energy consumption, and service conditions.

The proposed changes in the rates to be charged to direct customers correspond to an average rate increase of 5.0 per cent. As is the case for municipal utilities, the increase will vary among the 105 large industrial customers.

The proposed average rate increase for all customers, including Hydro's rural retail customers, is 4.9 per cent. This increase is based upon a total revenue requirement for 1987 of 4873 million dollars, which represents an increase of 344 million dollars over the primary revenue expected in 1986. Of this increase, 117 million dollars is forecast to be recovered through increased sales volume, leaving 227 million dollars to be recovered through the 4.9 per cent increase.

The chief factors responsible for the 1987 rate increase are the costs associated with new facilities placed in-service on the system, and escalating operations and fuel costs. These cost increases are partially offset by a reduction in the interest charges for facilities already in-service, as well as by higher forecast electricity sales in Ontario next year.

The rates proposed for 1987 are based essentially on the costing and pricing policies and procedures used for 1986. Hydro is deferring any major rate structure reform for the next two years. Meetings are being held between Hydro and the two major customer representative associations, the Municipal Electric Association (M.E.A.) and the Association of Major Power Consumers of Ontario (A.M.P.C.O.) to discuss rate structure reform in time for 1989 rates.

The proposal for 1987 rates was developed taking into account forecasts of moderating rate pressures in future years. In this context, the 1987 rate increase of 4.9 per cent represents reasonable steps towards providing rate stability and an acceptable balance between rate and financial soundness objectives.

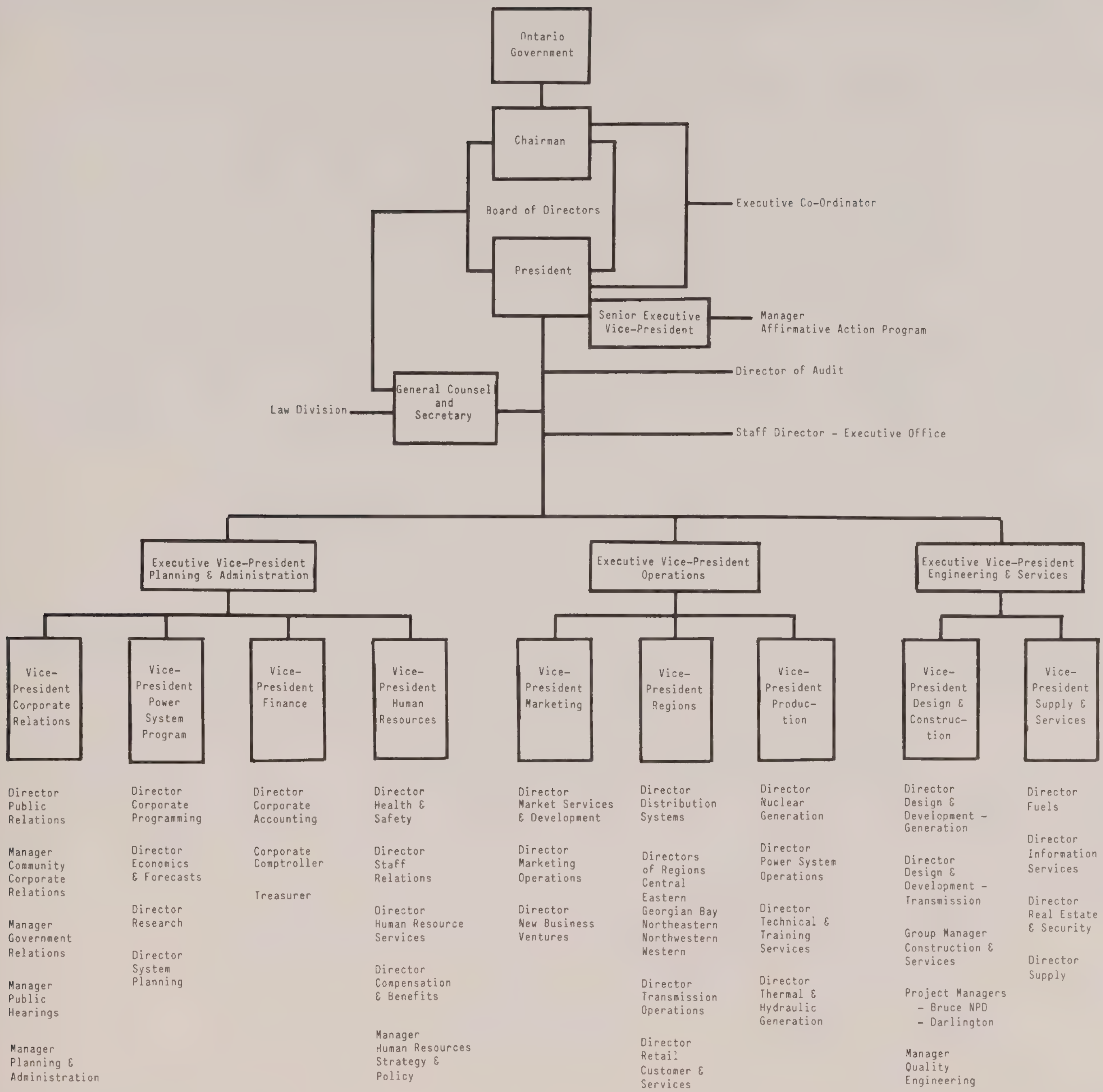
Sincerely,

Tom Campbell

Encl.
(see chapter 10C of
this Submission)

REPORTING RELATIONSHIPS*

Appendix 2



* In this chart, each office holder both reports to a Vice-President or higher and oversees work programs having corporate-wide effects.

MARCH, 1986

FINANCIAL DEFINITIONS

CAPITAL PROGRAM COSTS are the costs associated with the construction and commissioning of capital facilities, the interest associated with the financing of these facilities during construction, major modifications to these facilities, the production of heavy water, training costs, and the purchase of minor fixed assets.

CASH FLOW COVERAGE RATIO measures the extent to which funds from operations cover interest payments.

$$= \frac{\begin{array}{l}\text{funds provided from operations} \\ +\ \text{net interest} \\ +\ \text{interest charged to fuel for electric generation} \\ -\ \text{interest on accrued provisions}\end{array}}{\begin{array}{l}\text{gross interest} \\ -\ \text{interest on accrued provisions}\end{array}}$$

DEBT = bonds and notes payable
+ short-term notes payable
+ other long-term debt
+ accrued provisions
- unamortized foreign exchange gain/loss

DEBT RATIO measures the extent to which assets are financed by debt $= \frac{\text{debt}}{\text{debt+equity}}$

EMBEDDED COST OF DEBT is the weighted average interest rate (%) on outstanding long-term debt as at the previous year-end.

EQUITY represents the amounts invested in the electricity system, which have been contributed by customers in the form of net income or invested by the Province of Ontario.
= equities accumulated through debt retirement appropriations
+ reserve for stabilization of rates and contingencies
+ contributions from the Province of Ontario as assistance for rural construction

FINANCIAL SOUNDNESS is the ability to meet financial obligations and to withstand situations that have potential adverse financial consequences.

GROSS INTEREST = interest and amortization of bond discount on bonds payable
+ interest on notes payable
+ interest on bank loans
+ interest on other long-term debt
+ interest on accrued provisions
+ foreign exchange on bond interest payments
- amortization of gain/(loss) on premature retirements

INTEREST CAPITALIZATION RATE is the weighted average interest rate of recent long-term debt associated with the capital program.

INTEREST CAPITALIZED is the portion of gross interest associated with the financing of assets under construction (including heavy water production) and unamortized advances for fuel supplies.

INTERNALLY GENERATED CASH FLOW = funds provided from operations.

INTERNAL TRANSFERS (fuel and fuel-related) consist of the credit for internal sales, the Bruce steam transfer credit, and the cost of commissioning electricity.

LEVEL OF INTEREST COVERAGE measures the extent to which net income covers gross interest payments.

$$= \frac{\text{net income} + \text{gross interest} - \text{interest on accrued provisions}}{\text{gross interest} - \text{interest on accrued provisions}}$$

NET INCOME REQUIREMENT is the net income level incorporated in the rate proposal which reflects the balancing of rate, capital availability and financial soundness considerations.

NET INCOME TARGET is based on a coverage of 1.05 on interest charged to operations combined with a coverage of 1.50 on interest capitalized, and a cash flow coverage ratio above 1.0.

NET INTEREST, referred to as "interest" in the Statement of Operations, represents the interest costs attributable to the debt used to finance the assets in-service.

= gross interest
- interest charged to construction in progress
- interest charged to heavy water production
- interest charged to unamortized advances for fuel supplies
- interest charged to fuel for electric generation
- interest earned on investments

NUCLEAR AGREEMENT PAYBACK results from the Pickering Agreement between Ontario Hydro, Atomic Energy of Canada Ltd. and the Province of Ontario. The three parties of the Agreement shared the capital cost of constructing the nuclear-fuelled Pickering Units 1 and 2, and share proportionally in a payback. The payback represents, in a broad sense, the net operational advantage of having electricity generated by Pickering Units 1 and 2 as compared to similar coal-fuelled units.

POWER PURCHASED represents firm and secondary purchases of power from Hydro-Quebec and Manitoba Hydro, as well as secondary purchases from the United States.

QUALITY OF INTEREST COVERAGE measures the proportion of gross interest costs which is charged to operations.

$$= \frac{\text{net interest} + \text{interest charged to fuel for electric generation} - \text{interest on accrued provisions}}{\text{gross interest} - \text{interest on accrued provisions}}$$

RATE BASE consists of all assets (in-service or under construction) less amounts on which it is not appropriate to earn a return.

= total assets
- accounts payable and accrued charges
- accrued interest
- contributions from the Province of Ontario as assistance for rural construction
- unamortized debt costs

RETURN ON AVERAGE RATE BASE = $\frac{\text{net income + gross interest}}{\text{average rate base}}$

RETURN ON EQUITY = $\frac{\text{net income}}{\text{equity}}$

REVENUE REQUIREMENT = costs as per Statement of Operations
+ net income requirement
- revenues for secondary power and energy

Appendix 4

SUMMARY OF PROCESS FOR DEVELOPING THE RATE PROPOSAL FOR 1987

General

The preparation of the financial aspects of the 1987 rate proposal is coordinated by the Comptroller's Division with key inputs being provided by various groups within the organization. A consistent set of planning assumptions and a number of complex financial forecasting models are used to develop the forecast level of revenues at current rates and the revenue requirement. The overall average rate increase for the rate year reflects the difference between revenue requirement and revenue at current rates.

Preparation of the revenue requirement forecast is based on primary assumptions on the economic outlook and load forecast, and a number of other consistent financial and operational planning assumptions. All economic planning indices are based on the current Economic Outlook and supplemented by the most current Financial Markets Outlook. The Load Forecast defines the primary peak power and energy demands expected to be required by customers during the forecast period.

Based on these primary inputs, the revenue and cost elements of the Financial Forecast are determined, as outlined below.

Revenues

The forecast of primary revenues at currently approved rates is prepared based on the Load Forecast, with additional detailed inputs concerning the sales mix and specific customer characteristics supplied by the Regions and Marketing Branches.

Secondary sales and revenues are forecast by the Power System Operations Division.

Operation, Maintenance and Administration

OM&A costs for the budget and rate years are determined during the annual budgeting process. OM&A costs for the rate year are updated to reflect the impacts of the latest economic outlook on escalation assumptions, and the impacts of any other significant assumption changes since the budget was developed.

Fuel and Fuel-Related Costs

Fuel and fuel-related cost forecasts are produced primarily by the Production Branch. The Branch initially produces a detailed station-by-station energy production plan (the Consistent Energy Set) that will meet the combined primary and secondary demand as identified in the Load Forecast and the secondary sales forecast. This plan takes into account the most up-to-date information regarding station reliability factors, anticipated power purchases, forecasts of hydraulic production and other factors. The Branch, in conjunction with Fuels Division, also produces a plan of fuel deliveries, consumptions and inventory level consistent with the anticipated use of the stations. The production plan, together with fuel price information supplied by Fuels Division and actual current station fuel inventory data provided by the Corporate Accounting Division, is used to model consumption costs and the corresponding revenue requirement for fuels. The costs for power purchased, water rentals, payback expense and the other components of the fuel and fuel-related costs are forecast in a similar manner.

Depreciation

The forecast of depreciation expense consists of the charge associated with assets currently in-service, the charges associated with assets that are planned to be placed in service during the forecast period, as well as other asset related charges such as decommissioning and fuel channel removal charges and other depreciation adjustments.

Charges on existing assets are based on a combination of data supplied by Corporate Accounting Division plus forecasts of retirements of assets. A forecast of the value of assets to be placed in-service is derived from the forecast Capital Program, and forecast depreciation charges for these assets are calculated.

Recommendations of the Depreciation Review Committee on items such as asset service lives, decommissioning and pressure tube removal provisions, and amortization rates are also factored in. Forecasts of other charges classified as depreciation expense are based on historical trends, as well as other specific forecast information.

Interest and Foreign Exchange

The forecast of interest expense is similar to the depreciation forecast in that a component of cost is associated with the existing debt, and additional costs are related to debt expected to be issued during the forecast period. Details on existing debt are provided by Corporate Accounting Division.

The expected cost of servicing this debt is modelled taking into account forecasts of foreign exchange rates, debt maturities and premature retirements.

Future borrowing requirements are forecast taking into account the Capital Program the forecast of debt maturities and premature debt retirements and other cash outflows. These are forwarded to a Treasury Division for the development of a borrowing program that will meet the cash needs of the Corporation over the forecast period. The details of this program, combined with the forecast of interest and foreign exchange rates in the Financial Markets Outlook, enable s the Comptroller's Division to model the cost of servicing such debt.

These total interest costs, together with interest on provisions and other miscellaneous interest expenses, are reduced by forecasts of interest credits such as interest capitalized in the capital program, investment income, and interest charges allocated to other assets such as fuel supplies. These allocations are calculated by the Comptroller's Division with the assistance of the Treasury Division and Fuels Division.

Foreign exchange costs, which represent primarily the recognition of gains or losses as defined by accounting policy on the outstanding principal amounts of foreign debt, are forecast by the Comptroller's Division. Foreign exchange cost forecasts are based on the existing foreign debt, forecast new foreign debt issues, if any, forecast hedging activities provided by Treasury Division, and the forecasts of exchange rates contained in the Financial Markets Outlook.

Net Income Determination

In years for which rates have been set, net income represents the surplus of revenues over costs. For purposes of setting rates however, net income is a component of the revenue requirement. The appropriate level of net income is determined taking into account three factors, namely; the level of rate increase, capital availability and financial soundness. It is reviewed by senior management and approved by Hydro's Board of Directors.

Cost of Power Allocation

Once the total revenue requirement is established, it is allocated by the Comptroller's Division to customers based on their forecast usage of peak power and energy as well as their forecast specific service conditions. These service conditions relate to voltage levels, types of contract (eg firm or interruptible) and use of specific distribution stations and low voltage lines.

The customer revenue requirements and detailed unit costs derived from the cost of power allocation are forwarded to the Marketing Branch for rate-setting purposes.